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DEMONSTRATION OF NATURAL GAS REBURN FOR NO_X EMISSIONS REDUCTION AT OHIO EDISON COMPANY'S CYCLONE-FIRED NILES PLANT UNIT NO. 1

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Prepared for:

Environmental Protection Agency (EPA)
Gas Research Institute (GRI)
Electric Power Research Institute (EPRI)
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CONVERSION TABLE

To Convert From	To	Multiply by
in	m	2.540×10^{-2}
ft	m	3.048×10^{-1}
ft^2	m^2	9.290×10^{-2}
ft^3	m^3	2.832×10^{-2}
mile	km	1.609
lb	kg	4.536×10^{-1}
ton	kg	9.072×10^{2}
ft/sec	m/s	3.048×10^{-1}
lb/hr	kg/sec	1.260×10^{-4}
tons/hr	kg/sec	2.520×10^{-1}
gal	m^3	3.785×10^{-3}
lb/in^2	kPa	6.895
HP	W	7.460×10^{2}
Btu	J	1.055×10^{3}
Btu/lb	kJ/kg	2.326
Btu/hr	W	2.931×10^{-1}
cfm	m^3/s	4.719×10^{-4}
ft^2/1000 cfm	$m^2/1000\ m^3/s$	1.968×10^{-2}
gr/dscf	kg/m^3	2.288×10^{-3}
in WG	Pa	2.491×10^{2}
lb/mmBtu	ng/J	4.299×10^{2}
°F	°C	°C = (5/9) (°F-32)
psig	Pa (absolute)	6895 (psig + 14.7)
lb NO_X/mmBtu	ppm NO_X at 3% O_2	714.

DISCLAIMER

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EXECUTIVE SUMMARY

Passage of the 1990 Clean Air Act Amendments underscored the need for establishing commercially acceptable technologies for reducing power plant emissions, especially oxides of nitrogen (NO_x) and sulfur dioxide (SO_2). NO_x and SO_2 lead to formation of acid rain by combining with moisture in the atmosphere to produce nitric and sulfuric acids. NO_x also contributes to the formation of "ground level" ozone. Ozone is a factor in the creation of smog, leads to forest damage, and contributes to poor visibility. Currently, electric utility power plants account for about one-third of the NO_x and two-thirds of the SO_2 emissions in the U.S. Cyclone-fired boilers, while representing about 9% of the U.S. coal-fired generating capacity, emit about 14% of the NO_x produced by coal-fired utility boilers.

Given this background, the Environmental Protection Agency (EPA), the Gas Research Institute (GRI), the Electric Power Research Institute (EPRI), the Department of Energy-Pittsburgh Energy Technology Center (DOE-PETC), and the Ohio Coal Development Office (OCDO) sponsored a program led by ABB Combustion Engineering (ABB-CE) to demonstrate reburning in a cyclone-fired boiler. Ohio Edison provided Unit No. 1 at its Niles Station for the reburn demonstration along with financial assistance. The Consolidated Natural Gas Company (CNG), specifically East Ohio Gas, also provided technical and financial contributions. Working as subcontractors with ABB-CE on the program were Energy System Associates (ESA) and Spectrum Diagnostix, Incorporated.

Reburn technology reduces NO_x emissions by creating a second combustion or "reburn" zone downstream from the primary combustion zone. The injection of this reburn fuel creates a fuel-rich zone in which the NO_x formed in the main combustion zone is converted to molecular nitrogen, carbon dioxide, and water vapor by the reaction of NO_x with carbon-hydrogen intermediates from the second, or reburn, fuel feed. Any unburned fuel leaving the reburn zone is subsequently burned to completion in a downstream burnout zone where burnout air is injected. Reburning is especially attractive for cyclone-fired furnaces since conventional low NO_x burners, or low NO_x burners in concert with over fire air cannot be used since low NO_x burners typically operate at lower temperatures, a condition which would prevent slag flow, a necessary requirement for cyclone furnaces. Most cyclone boiler operators do not want to alter fuel/air stoichiometries in the cyclone because of the potential negative effects on tube wastage.

A natural gas reburn system was installed on Ohio Edison's Niles Unit No. 1, a 115 MW (gross) cyclone-fired boiler. The objective was to demonstrate that 50% NO_x reduction could be achieved at full load and that the reburn system could be operated without adversely affecting boiler thermal performance and component life.

The project at the Niles plant represented the first commercial demonstration of a natural gas reburn system. Although the effectiveness of reburning as a NO_x reduction technique was shown in many laboratory and pilot scale experimental tests, the subject demonstration was the first to look at the total impact of a reburn system in a commercial boiler. Though NO_x reduction was the focus of the demonstration, it was even more important that the reburn system not cause any unacceptable side effects on boiler operation and component life. Indeed, execution of this project turned up a few unexpected results illustrating just why R&D demonstrations are conducted. It is believed that results from this project were valuable in their own right and, furthermore, that lessons learned here provided very useful input and direction to those who would conduct follow-on demonstrations of reburn systems.

The original reburn system was designed to employ flue gas recirculation (FGR) as a carrier gas for mixing of the natural gas with the bulk flue gas in the reburn zone. The original system met the NO_x reduction and boiler thermal performance objectives. However, much thicker slag deposits formed on the back wall of the furnace. The deposits, which were as much as 12 inches thick, had little or no effect on boiler performance and did not prevent completion of the original system test program. However, long-term operation of the original reburn system was unacceptable for several reasons. Slag falls during boiler operation could have a damaging effect on screen tubes at the bottom of the furnace; the possibility of slag falls during slag removal operation was a risk to personnel; and slag accumulation could cause blockage and misdirection of the reburn fuel jets and reduced durability of the reburn nozzles. For these reasons there was a need to identify the cause of the problem and to resolve it.

Importantly, resolution of the deposition problem with the original reburn system led to a simpler, less expensive reburn system. The original reburn system employed flue gas recirculation (FGR) as a means of better mixing the natural gas (reburn fuel) with the bulk flue gas. Proof-of-concept (POC) testing showed that the thicker ash deposit was returned to its normal thickness when the FGR was eliminated. The relatively cool FGR had caused the normally thin, molten, running slag layer on the back wall of the secondary furnace to become cooler and therefore thicker than the basecase condition.

A modified reburn system was designed and installed in which the use of FGR was eliminated. As indicated in the POC testing, deposits on the back wall returned to normal thickness. NO_x reduction was initially lower than with the original system; but with continued operation and increased operator attention to cyclone air/fuel ratio control, NO_x reduction improved, and during the last period of long-term testing, full load NO_x reduction was better than that achieved with the original reburn system. Importantly, there were a number of other advantages with the modified system, both operational and economic: the modified system showed heat transfer distribution within the boiler to be much closer to the base case conditions, and the cost of the reburn system was lower due to the elimination of the FGR and associated equipment. The plant net heat rate was also improved by eliminating the power requirement for the gas recirculation fan. The elimination of FGR was considered sufficiently important from both an operational and economic standpoint that a reburn system employing direct injection of natural gas was used as the preferred design when conducting the economic analysis of natural gas reburn systems for the entire family of cyclone furnaces.

The modified reburn system design and installation at Niles Unit No. 1 were relatively simple. The key components for the reburn zone were the reburn fuel injectors, modifications to the furnace water walls to permit penetration of the reburn fuel injectors in the reburn zone, and the natural gas piping, controls, valves, and connections between the natural gas pipeline and the furnace. Key components for the burnout zone were the ductwork, associated control dampers, and the windboxes and nozzle assemblies where combustion air was injected into the gas mixture from the reburn zone. Placement and configuration of reburn fuel and burnout air injectors were important to achieve sufficient residence time and mixing.

The reburn test program included parametric testing of the original reburn system in which natural gas was injected into the reburn zone mixed with recirculated flue gas (FGR), as well as parametric testing of the modified reburn system followed by long-term dispatch testing to measure system performance and operability during normal boiler operation. The project provided the following key conclusions concerning emissions reduction performance and operability of the natural gas reburn process in cyclone-fired furnaces:

- Natural gas reburn significantly reduced NO_x emissions from the Niles Unit No. 1 cyclone fired furnace. Reburn also affected CO emissions. Specific NO_x and CO emissions behavior was observed as follows:
    - NO_x reductions of 30 to 70% were measured during parametric testing of the original system at full load.
    - NO_x reduction of up to 55% was demonstrated at full load with acceptable boiler operation and CO emission lower than 100 ppm using the modified reburn system.
    - NO_x reduction of 66.8% was demonstrated at full load with acceptable boiler operation and CO emission of 1514 ppm using the modified reburn system.
    - Reburn zone stoichiometry (RZS) was the most significant operating variable affecting NO_x reduction by the reburn process.
    - NO_x emissions decreased linearly as RZS was decreased.
    - CO emissions increased exponentially as RZS was decreased.
    - For long-term operation of a commercial reburn system RZS should be maintained slightly above 0.9 to simultaneously minimize both NO_x and CO. Because of the inability to maintain precise coal/air ratios in each of the cyclones at Niles No. 1 during long-term testing, simultaneous NO_x and CO emissions were minimized at RZS of 0.94.

- Natural gas reburn had a minimal effect upon boiler performance and electrostatic precipitator (ESP) performance.
    - During 18% natural gas reburn testing with the original system, waterwall heat absorption decreased by approximately 5% and convective pass heat absorption increased by 5%; attemperator spray flows, operating in a normal range, were able to control steam temperatures at the design levels.

- Boiler efficiency decreased by 0.6% with 18% natural gas reburning in the original system due principally to higher latent heat of vaporization losses caused by greater moisture formation from combustion of natural gas.
- ESP collection efficiency was lowered slightly during reburn system operation due to lower ESP inlet loading and a non-optimized flue gas conditioning system.

- Operation of the original reburn system led to the buildup of much thicker ash deposits on the rear wall of the furnace at Niles No. 1.

  - Long term operation of the reburn system could not be sustained with the original reburn system due to abnormally heavy slag buildup on the back wall and over the reburn fuel injectors.
  - The primary cause of thicker ash deposits was the cooling effect of FGR on the rear wall.
  - The cooler FGR caused the normally thin, molten deposits to become thicker, sintered deposits as they equilibrated to the change in the thermal environment.

- The original reburn system was replaced by a modified reburn system in which the FGR system was eliminated. Eliminating FGR eliminated the ash buildup deposition problem. The modified reburn system also provided several cost and operations advantages over the original reburn system.

  - Lower capital cost.
  - Smaller space requirement.
  - Elimination of the high maintenance, energy intensive FGR fan.
  - More favorable furnace heat absorption distribution. Radiant section heat absorption increased and convective section heat absorption decreased resulting in lower attemperator water flow requirement. Boiler efficiency was essentially the same as that of the original system.

- The modified reburn system initially showed a NO_x removal efficiency about 8% lower than the original reburn system. Possible causes for the lower NO_x reduction were initially thought to be soot formation by the natural gas in the absence of the recirculated flue gas and decreased mixing of the natural gas due to elimination of the recirculated flue gas. However, NO_x reduction improved as long-term testing continued; during the last period of long-term testing, NO_x reduction was greater than that achieved with the original reburn system. Operator familiarity with the system and closer control of individual cyclone fuel/air ratios was thought to be the reason for improvement.

- Water injection into the reburn zone was initially thought to improve NO_x reduction during testing with the modified reburn system. A water leak in one of the water-cooled reburn fuel injector guidepipes seemed to correspond directly with increased NO_x reduction. However controlled water injection tests conducted after completion of the long-term tests provided no improvement in NO_x reduction compared to the NO_x reduction achieved during the final series of long-term tests. Controlled water injection did however accomplish the following:

- Lower CO levels; CO emission of 46 ppm and NO_x emissions of 325 ppm, corrected to 3% O_2, were achieved with water injection compared to CO emission of 110 ppm at the same NO_x emission level without water injection.
- The ability to operate the reburn zone at lower stoichiometries (lower NO_x), while maintaining the CO at acceptable levels.

- Reburn systems installed on pressurized furnaces, such as Niles Unit No. 1, can result in a hazardous situation if a casing leak occurs in the vicinity of the reburn zone because of the presence of combustible gases. Possible commercial solutions were suggested:

  - Convert pressurized units to balanced draft by adding an induced draft fan and associated equipment.
  - Convert tangent tube pressurized units such as Niles No. 1 to fusion welded walls by adding fusion welds between the tubes.
  - Erect an enclosure around the reburn zone which would operate at a slightly higher positive pressure than the furnace pressure to assure that any leakage would be into the furnace.
  - Erect a "hood-like" structure around the upper part of the furnace so that gas composition could be constantly monitored for possible changes.

  It is unlikely that the first two could be economically justified. However, the third and fourth options would be much less capital-intensive and could be configured to ensure safe reburn system operation.

- Operational constraints place a limitation on the reburn fuel feed rate and corresponding NO_x reduction during reduced load conditions.

  - In order to assure effective tapping of slag from cyclone-fired units, it is necessary to maintain a minimum heat release rate to the primary furnace and the corresponding coal feed rate to the cyclone combustors.
  - The minimum heat release requirement in the slag tap region of the primary furnace is a function of the furnace size, cyclone design, and coal ash fusibility.
  - Since the fuel fed to the reburn zone does not contribute to heat release in the slag tap region, reburn fuel must be reduced and finally discontinued as boiler load is reduced beyond a certain level.
  - Because the proportion of reburn fuel used at reduced boiler loads is decreased and ultimately turned off below a certain load, overall NO_x reduction is less for reburn systems installed on cyclone-fired furnaces which operate at reduced load for substantial periods. The NO_x concentration in the stack with reduced load, however, tends to remain nearly constant because the "baseline" NO_x also decreases with reduced load.

- The possibility of tube wastage during operation of the reburn system existed because the reburn process generated a substoichiometric (reducing) gas mixture in the reburn zone. A boiler tube monitoring program was conducted during the reburn system testing to address this possibility. The findings of tube monitoring program were as follows:

- The ultrasonic thickness testing in the waterwall sections was inconclusive since changes in tube thickness were below the sensitivity of the U.T. measurement. However, visual inspection of the waterwalls revealed that the tube surface appeared to be unaffected by reducing atmosphere corrosion.
- Ultrasonic thickness measurements of the superheater and reheater sections, following operation of the original reburn system, showed areas with an approximate 10% wall loss, with wastage in areas of the fifth stage superheater as high as 0.100" over a 20 month timeframe. Indicated tube loss is thought to be from a combination of erosion and corrosion.
- Tube wall thickness changes in the superheater and reheater sections during testing of the modified reburn system were significantly less. The reduced tube wastage during operation of the modified system, without FGR, is explained by the fact that the flue gas mass flows/velocities during modified reburn system operation were returned to basecase levels, thereby minimizing wastage due to erosion. Because tube wastage was not uniform, it is believed that erosion was the larger contributing factor between erosion and corrosion.
- The remaining superheater/reheater tube life analyses performed before and after the reburn project were inconclusive concerning any degradation due to high temperature oxidation. Final inspection values gave higher remaining tube life values than did initially obtained values.

- The cost effectiveness of natural gas reburn retrofit for reducing NO_x emissions from cyclone-fired furnaces depends upon several factors including the following: (1) the baseline NO_x and the expected NO_x removal efficiency of the process over the load range of the boiler, (2) the load profile of the boiler, (3) whether or not it is necessary to terminate reburn operation at some boiler load due to slag tapping requirements and if so at what load this requirement is imposed, and (4) the difference in fuel costs between natural gas and coal. A study of natural gas reburn economics indicated that natural gas reburning is most attractive for newer large units, particularly, base-loaded units.

Parametric testing and long-term testing during the Ohio Edison Reburn Demonstration project provided several recommendations for reducing NO_x and CO emissions by improvements to the reburn system design and operation. These are:

- Improve the control system for feed of coal and air to the cyclones in order to have better and more uniform control of RZS. In this way the reburn system will be better able to operate nearer to the optimum RZS which will provide higher NO_x reduction without aggravating CO levels.

- CO levels turned out to be a limiting factor for NO_x reduction. Decreases in RZS could clearly produce lower NO_x, but at the expense of unacceptably high CO. Better mixing of air in the burnout zone and biasing residence times toward the burnout zone, rather than the reburn zone, may result in lower NO_x because of the ability to achieve acceptable CO levels.

- Introduce a small controlled amount of H_2O with the natural gas in the reburn zone to reduce CO formation; this would allow lower RZS, higher NO_x reduction and acceptably low CO.
- Use stainless steel for water-cooled guide tubes and other components which are subjected to high temperatures in order to reduce the possibility of failure of reburn zone components.

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INTRODUCTION

Passage of the 1990 Clean Air Act Amendments has underscored the need for establishing commercially acceptable technologies for reducing power plant emissions, especially nitrogen oxides (NO_x) and sulfur dioxide (SO_2). NO_x and SO_2 lead to formation of acid rain by combining with moisture in the atmosphere to produce nitric and sulfuric acids (Bruck (1987), Hakkarinen (1987), and Johnson and Siccama (1983)). NO_x also contributes to the formation of "ground level" ozone. Ozone is a factor in the creation of smog, leads to forest damage, and contributes to poor visibility.

Electric utility power plants account for about one-third of the NO_x and two-thirds of the SO_2 emissions in the U.S. Cyclone-fired boilers, while representing about 9% of the U.S. coal-fired generating capacity, emit about 14% of the NO_x produced by coal-fired utility boilers.

Given this background, the Environmental Protection Agency (EPA), the Gas Research Institute (GRI), the Electric Power Research Institute (EPRI), the Department of Energy - Pittsburgh Energy Technology Center (DOE-PETC), and the Ohio Coal Development Office (OCDO) sponsored a program led by ABB Combustion Engineering, Inc. (ABB-CE) to demonstrate reburning on a cyclone-fired boiler. Ohio Edison provided Unit No. 1 at their Niles Station for the reburn demonstration along with financial assistance. The Consolidated Natural Gas Company (CNG), specifically East Ohio Gas, provided technical guidance as well as financially sharing in the program. Ohio Edison and East Ohio Gas both shared a portion of the differential between the cost of natural gas and coal. Working as subcontractors to ABB-CE on the program were Energy System Associates (ESA) and Spectrum Diagnostix, Incorporated. The Niles Unit No. 1 reburn system was started up in September 1990. This reburn program was the first full-scale reburn system demonstration in the U.S.

This report describes work performed during the program. The work included a review of reburn technology, aerodynamic flow model testing of reburn system design concepts, design and construction of the reburn system, parametric performance testing, long-term load dispatch testing, and boiler tube wall thickness monitoring. The report also contains a description of the Niles No. 1 host unit, a discussion of conclusions and recommendations derived from the program, a diskette containing tabulation of data from parametric and long-term tests, and appendices which contain additional tabulated test results.

5

REVIEW OF REBURN TECHNOLOGY

Introduction

The process of reburning, a fuel staging process that provides in-furnace reduction of nitrogen oxides (NO_x) emissions, has been demonstrated in laboratory, pilot scale, and full scale combustor test trials. In many cases, reduction of NO_x emissions of 50% and greater were demonstrated. These trials provided direction for practical application of reburning to full scale boilers. However, the results depend on the apparatus and operating conditions and must be adequately interpreted to provide the criteria necessary for the design of full scale utility reburning systems.

This review was conducted during the planning stage and equipment design for the Ohio Edison Reburn Project. The objectives of the review were to study previous experiments and to interpret the results in order to:

1) Establish reburn system design and operating parameters
2) Assess the relative importance of the parameters and establish appropriate values or value ranges for these parameters in terms of system performance and NO_x reduction efficiency.
3) Establish an overall set of design criteria for a full scale utility reburn system design.

General Description of the Process

The reburning process is an in-furnace NOx control technology that diverts some of the fuel and combustion air flows from the main burners and injects them above or downstream of the main flame. Reburning can be employed with any fossil fuel, or combination of fossil fuels, typically coal, oil, or natural gas. Natural gas is technically ideal because it contains no fuel nitrogen and it can be burned with relatively lower residence times. The reburning process involves the three zones shown in Figure 5-1:

1) <u>Primary Zone</u>: This is the main heat release zone where the majority of thermal energy is released to the boiler. This zone operates under overall fuel lean conditions although the burners can be of a low NO_x producing design with low levels of excess air; this, however, is not the case with cyclone-fired combustors which do not employ burners in the usual sense. The level of NO_x exiting from this zone is the level to be reduced in the reburning process.

2) <u>Reburn Zone</u>: This is the zone into which reburn fuel is injected (downstream of the primary flame zone) wherein NO_x reduction occurs. The nitrogen species entering this zone come

from two primary sources: (1) the "thermal NO_x" from fixation of nitrogen in the primary zone combustion air, and (2) "fuel NO_x" from the nitrogen contained in the primary fuel (coal in this case). Depending on the choice of reburn fuel (coal, oil, or natural gas) there could also be some nitrogen produced by the reburn fuel, if coal or oil was chosen. The reduction of NO_x is the result of hydrocarbon species from the reburn fuel reacting with NO and NO_2 from the primary zone to form N_2. Other products of this reduction zone are reactive nitrogen species (cyanogens) and partially reduced hydrocarbons. To optimize the NO_x reduction through reburning it is necessary to minimize the total reactive nitrogen leaving the reburning zone.

3) Burnout Zone: In the burnout zone, air is added to produce overall fuel lean conditions in order to oxidize the unreacted fuel from the reburn zone. In the burnout zone the remaining reactive nitrogen species (cyanogens) may be converted to either NO or N_2.

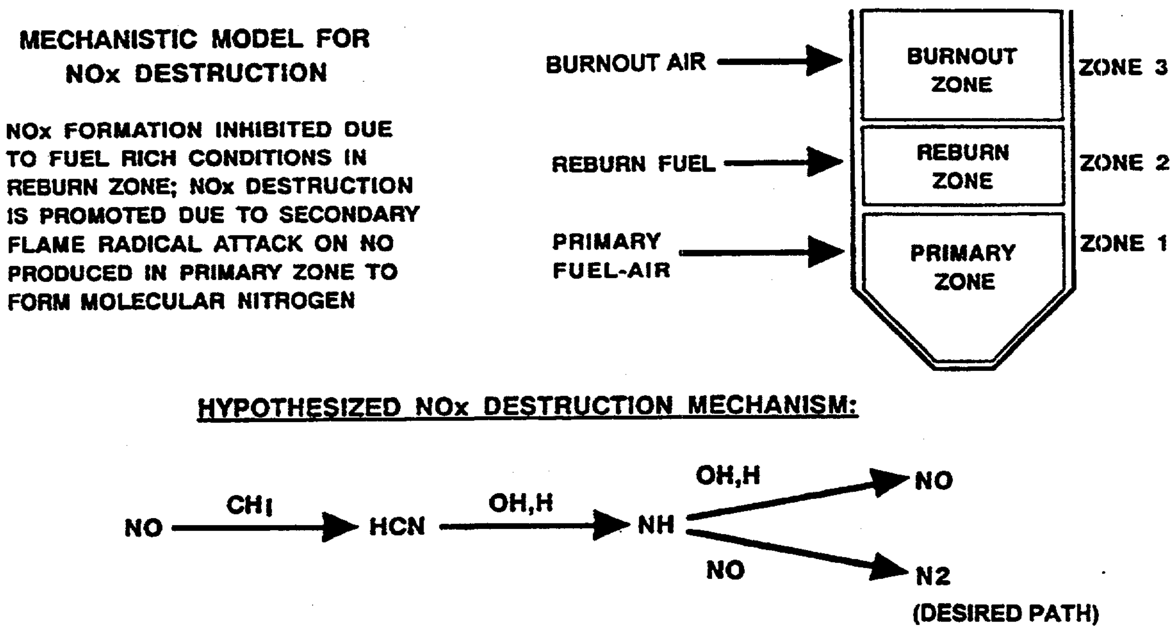


Figure 5-1
Schematic of Reburn Process

The use of separate fuel combustion stages to control NO emissions is not a totally new concept. The first practical system using this approach was commercialized by the John Zink Company in 1975 (U.S. Patent No. 3873671 to Reed et al.). The Zink system was given the trade name NOxIDIZER and was sold to reduce NO emissions from nitric acid plants. The first investigation for applying the process to reduce emissions from combustion processes was performed by Wendt et al. (1973), who injected CO and CH_4 downstream of the flame zone of a laboratory scale burner and measured significant reduction of NO emissions. Myerson (1974) carried out similar experiments using a second combustion stage to reduce NO emissions from automotive engines. The first commercial application of the process to utility furnaces was by Mitsubishi Heavy Industries.

The reburning process is known under different names, the names depending on the researchers or manufacturers applying the process. Several names are listed in Table 5-1. For simplification purposes, all of these processes can be called reburn. All of the processes involve fuel staging to provide in-furnace reduction of NO_x.

Table 5-1
Names used for the Reburn Process

ORGANIZATION/INVESTIGATOR	DATES	NAME
John Zink Company	1970s	NOxIDIZER
Wendt, et al./Shell Development	1970s	Reburning
Mitsubishi Heavy Industries (MHI)	1978	MACT (Mitsubishi Advanced Coal Technology)
EER	1980s	Reburning; Fuel Staging
KVB	1980s	In-Furnace Control of NO Formation (ICNF)
Babcock Hitachi	1980s	IFNR (In-Furnace NOx Reduction)
Hitachi Zosen	1980s	Three-Stage Combustion System
Ishikawajima Heavy Ind. (IHI)	1980s	IFNR (In-Furnace NOx Reduction)
Acurex	1980s	Fuel Staging

Fundamentals of the Reburn Process

Overview

The technology for reducing NO_x emission by the downstream addition of fuel has been under investigation for several years. Myerson (1974) and Wendt et al. (1973) conducted fundamental studies of the destruction of NO_x by injection of secondary fuel (hydrocarbons) and named the process "reburning". Since that time, research on reburning was conducted in Japan, and more recently in the United States. For example, Takahashi et al. (1982) of Mitsubishi Heavy Industries (MHI) documented MHI's research on the NO_x reduction process through hydrocarbon injection by reporting on the development of the Mitsubishi Advanced Combustion Technology (MACT), the first Japanese reburning concept. The MACT system diverts a small percentage of fuel from the main burner combustion zone and injects the fuel through upper injection ports with an inert fluid, usually flue gas. The balance of the combustion air is provided via overfire air ports. This research by MHI showed that nitrogen oxide (NO) formed during the initial stages of combustion could undergo significant conversion to molecular nitrogen by the injection of hydrocarbons. In the 1980's, research investigations and commercial demonstrations of this technology were conducted both in Japan and the U.S. Several of the projects were limited to the use of natural gas and/or oil as the reburn fuel; however a few investigated reburning with coal as primary or reburn fuel. To illustrate the scope of issues involved, a brief review of several recent investigations is given.

The work of Takahashi et al. at MHI (1982) led to further research by others including Miyamae et al. from Ishikawajima-Harma (1985), Mulholland and Hall (1985) and Mulholland and Lanier (1985) of Acurex/EPA, Greene, McCarthy, and Overmoe from EER (1985), and Mulholland and Hall of Acurex/EPA (1987). This research yielded slightly different results as to the applicability of different fossil fuels as a reburn fuel. For example, from the results obtained from a small test facility, Takahashi concluded that the NO_x reduction efficiency of the reburn process was independent of the reburn fuel type and of the reburn zone inlet NO_x level. Subsequent results from other researchers (such as Mulholland et al. (1985)) indicated that reburning efficiency is influenced by both of these parameters. Most of the early researchers concluded that the effectiveness of the NO_x reduction is a strong function of the residence time in the reburn zone. Furthermore, they generally found that an optimal reburn zone stoichiometry (defined as the actual oxygen in the region divided by the oxygen required for complete combustion of the fuel to carbon dioxide and water vapor) of about 0.8 to 0.95 was desirable, with MHI promoting a value of 0.95 as an "optimal compromise", taking boiler performance into consideration.

The results reported by Mulholland et al. (1985) indicate that substoichiometric reburn zone conditions are optimal and that the reburn zone inlet NO_x level is a key parameter in determining the reburning NO_x reduction efficiency. They also stated that the nitrogen content of the reburn fuel was important in determining the NO_x reduction efficiency that can be achieved. These researchers also recommended an optimal reburn zone residence time of approximately 0.5 seconds.

Miyamae et al. (1985) worked with natural gas and gas phase volatile matter evolved from pulverized coal. In their work it was concluded that a main burner stoichiometry of 1.1 was optimal. Also, they indicated that while a 50% NO_x reduction efficiency was possible in a laboratory test facility, only 15 to 20% NO_x reduction efficiency would be possible with a multiburner full scale demonstration. They also concluded that a reburn residence time of about 0.5 seconds was optimal.

Okigami et al. (1985) utilized a South African coal and an Australian coal as the reburn fuel. Although they did not present quantitative design and operating characteristics of the reburn zone, residence time or stoichiometry, they did demonstrate that significant NO_x reduction (up to 60%) could be achieved using coal as a reburn fuel.

Pilot scale work in the U.S., McCarthy et al. (1985), confirmed that the optimum reburn zone stoichiometry is close to 0.9. The results also showed that there was an increase in reburning efficiency when the reburn zone temperature was increased from 2600°F to 2840°F.

Thermochemistry

The degree of conversion of fuel-bound nitrogen (FBN) to molecular nitrogen (N_2) is determined by the thermodynamics of the system (temperature, pressure, and chemical composition of the gas mixture), and the rates of reaction in the flame zone. In practical combustion systems the reaction of FBN and NO to N_2 may be kinetically constrained and provision of sufficient residence time in a fuel-rich zone is therefore essential for high conversion to N_2. The partially reacted nitrogenous or cyanotic (CN) compounds in a fuel-rich flame zone may have different origins: they may be pyrolysis products of nitrogen-bearing fuels, products of the fixation of atmospheric nitrogen by hydrocarbon fragments early in the flame, or the result of reactions due to the secondary injection of hydrocarbons into the NO-containing burned gas, sometimes referred to as "prompt NO_x". The various pathways for formation and destruction of NO are shown schematically in Figure 5-2. In the combustion air staging technique, conversion of FBN to N_2 rather than to NO is mainly due to fuel-rich conditions prevailing in the primary flame zone near the burner.

In fuel staging, the destruction routes of NO shows that NO can be destroyed in two ways. It can be reduced either by reacting with amines (NH_i) to form molecular nitrogen or by reacting with hydrocarbon radicals such as CH and CH_2 to produce hydrogen cyanide which in turn is converted to NH_3. The ammonia thus formed can subsequently reduce NO to N_2 or be directly converted to N_2. In the case of pulverized coal, volatile matter evolves from the coal upon injection into the hot furnace environment (approximately 2500 °F). The volatiles thus formed crack into compounds which contain nitrogen such as HCN and NH_3 and non-nitrogen containing species such as CH_4 and C_2H_2. These species can then start the NO_x reduction process. Under reburning conditions, it is felt that the CH_i radicals play an important part in reducing the NO_x to N_2. A critical step in the reburning reaction sequence is the conversion of HCN to NH_i via interaction with the free radical pool (O, OH, H). Once formed, the NH_i species further reacts with NO to form N_2.

Kinetics

The fundamental reactions leading to the formation and destruction of NO_x are too numerous and complex to be described in detail here. However, the kinetics of the NO_x production/destruction reactions as applied to reburning can be summarized by the following discussion.

The formation of NO_x during fossil fuel combustion is a process involving contributions from both the fixation of atmospheric nitrogen (thermal NO_x) and the oxidization of nitrogen bound chemically in the fuel (fuel NO_x). NO_x generation via the thermal fixation of atmospheric nitrogen can be approximated in large boilers by the use of a highly temperature dependent chemical reaction rate determined by Zeldovich (1974). The rate of formation is exponentially dependent on temperature and is proportional to the square root of the oxygen concentration. Reducing both the amount of oxygen available to the fuel and reducing the combustion temperature are effective methods of controlling NO_x formation via the thermal mechanism. Although only a fraction of the nitrogen in fuel is converted to NO_x, fuel NO_x can represent a major fraction of the total NO_x. Fuel nitrogen conversion is a particularly important source for NO_X formation in coal-fired furnaces. For example, when firing a high-nitrogen fuel in a conventional steam generation unit, fuel nitrogen accounts for 50 to 80% of the NO_x emitted.

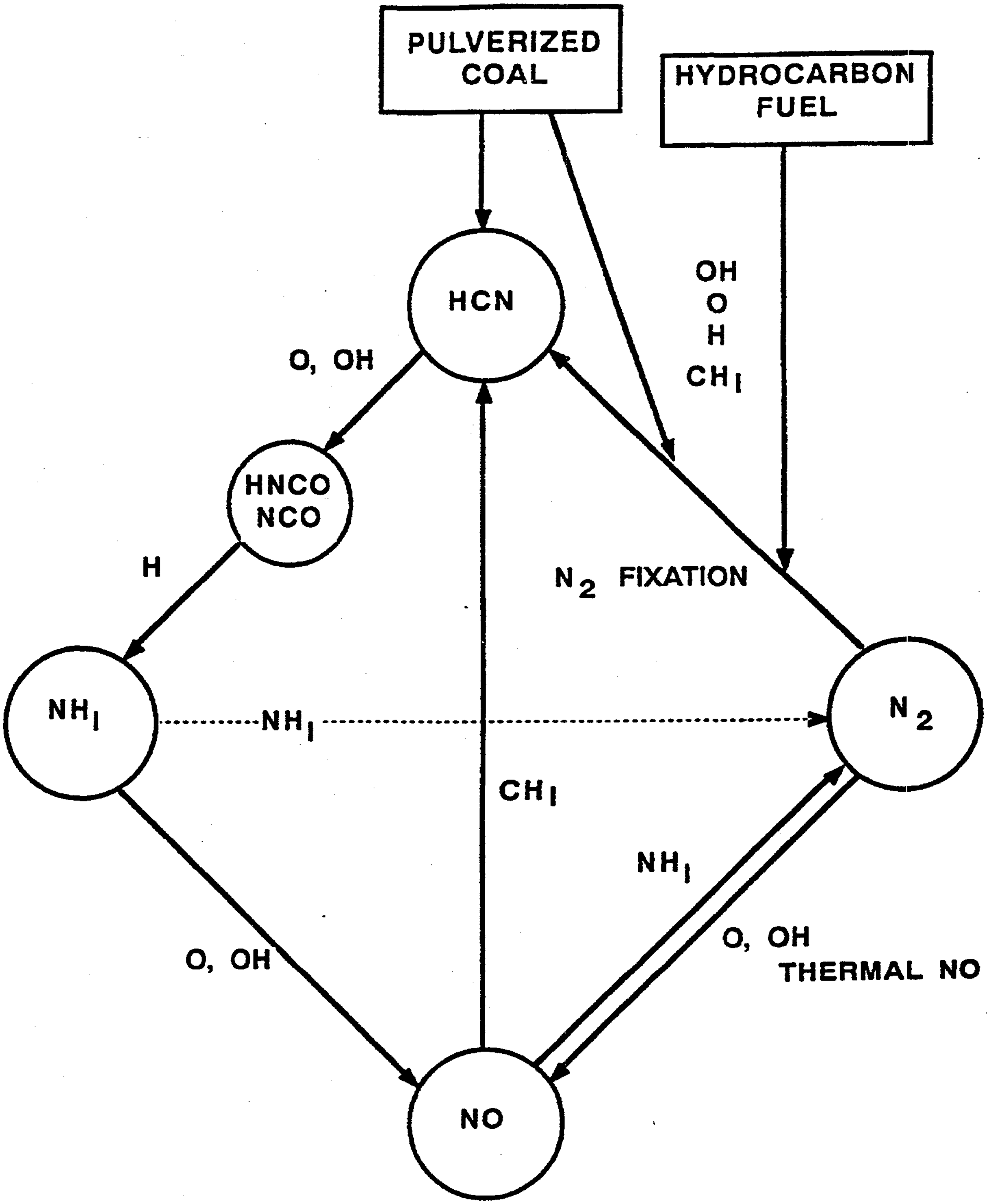


Figure 5-2
Schematic of the Formation and Destruction Mechanisms of NO

A generalized conceptual mechanism for NO_x formation and reduction is illustrated in Figure 5-3. Recent experimental evidence of NO_x kinetics supports this sequence of events, Toqan et al. (1987):

- Fuel nitrogen rapidly and irreversibly breaks down to HCN
- HCN is irreversibly converted to NCO through a rate-controlling step
- HOCN and NCO rapidly interchange with one another and react to form NH_i species
- The NH_i species are equilibrated among themselves and, except for possibly N, provide the branching point for the production of NO or N_2
- The oxidizer and NH_i species which provide the branching point are uncertain.

Based on this model, when fuel containing nitrogen is fed into a furnace or combustor, a large fraction of the nitrogen compounds evolve into the gas phase as the fuel volatilizes. The volatile nitrogen is predominately in the cyanogen form during the combustion of oil or bituminous coal, although a substantial fraction (originating as amino-bonded species) may evolve as NH_i from subbituminous or lignite coals. The cyano species are thought to react with the flame-generated free radicals to form the amine species that can further react with oxygenated species to form NO, or with NO to form N_2. The fractional conversion to NO is therefore highly sensitive to the amount of available oxygen (excess air) and the mixing conditions that determine the contact time between reactive nitrogenous and oxygenated species. The amino and cyano subsystems are often idealized for modeling purposes as being in partial equilibrium.

This model indicates that there are two pathways of NO_x destruction. For the first process, NO can react with hydrocarbon radicals (symbolized by CH) to reform HCN/CN. This reaction takes place under fuel-rich conditions in any staged combustion process, but is maximized during the reburning process. This recycle of NO to HCN provides a second opportunity to produce N_2, and can result in substantial reductions in NO_x emissions. The other pathway to NO_x destruction takes place by reaction of NO with NH_i radicals, and is known to occur at low temperatures (1600-2000°F) and where local oxygen concentrations are low.

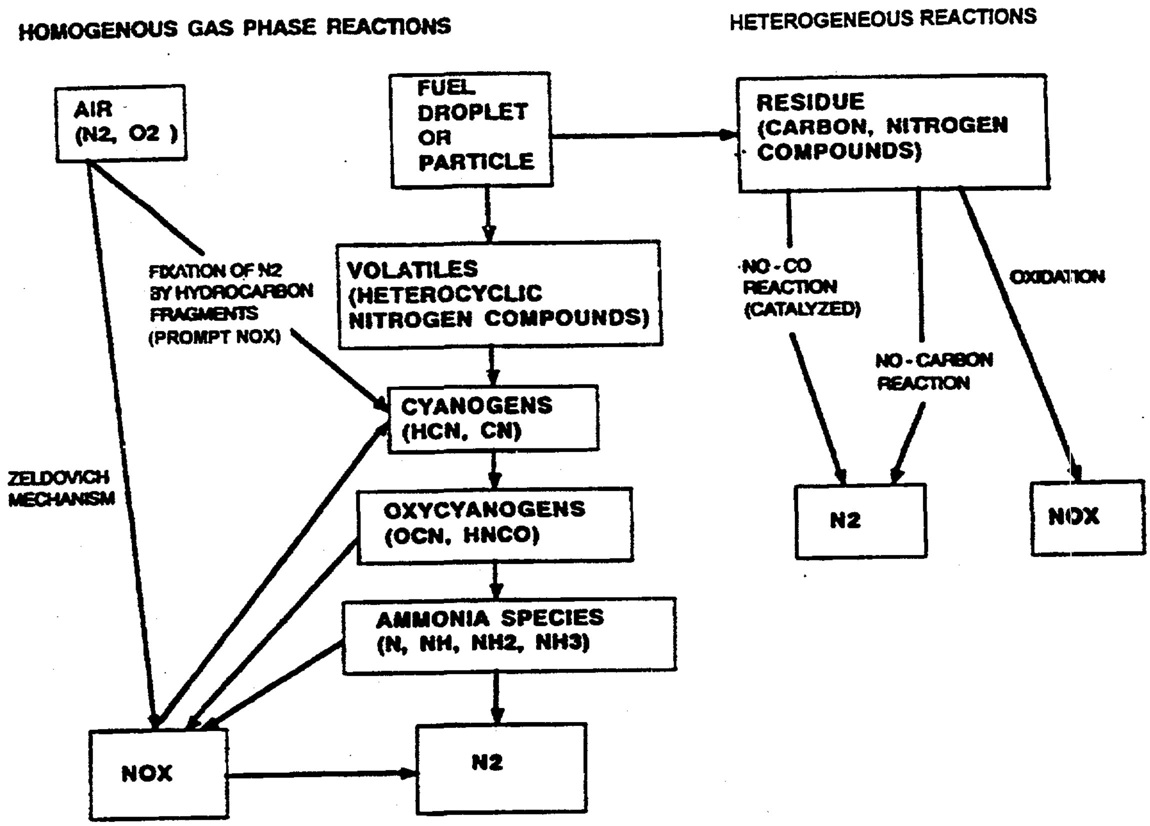


Figure 5-3
Generalized Conceptual Mechanism for NO_x Formation and Reduction

Detailed chemical kinetic modeling for the reduction of NO has been performed for simple flames, shock tubes, and full-scale combustors. For gas-phase NO_x modeling, typical kinetic models contain mechanisms consisting of from 30 to over 100 elementary reactions. Each reaction requires specification of reactants, products, thermochemistry, and rate coefficients as a function of temperature. The rate laws for such mechanisms consist of sets of coupled ordinary differential equations which must be integrated numerically. In general, the computations are difficult due to large, rapid excursions in the rates of many of the free radical reactions ("stiffness"). An excellent example of numerical analysis for NO_x formation/destruction is given by Toqan, et al. (1987). The numerical calculations were carried out using CHEMKIN, a chemical kinetic code developed at Sandia National Laboratory, Kee et al. (1980), coupled with a differential equation solver developed at Lawrence Livermore Laboratory.

Experimental Investigations

Overview of Experimental Parameters

This section provides a review of experimental work conducted to develop reburn technology. Data for thirty-five (35) experimental studies are compiled to address experimental parameters listed in Table 5-2. The thirty-five experimental studies are summarized in Table 5-3, Sheet 1 through Sheet 6. The tables list data for the Overall System, Primary Combustor, Reburn Section, and Burnout Zone. More detailed descriptions of experience gained for each of the sections of the reburn system are given in the following subsections.

Primary Zone

Three primary zone variables have bearings on the effectiveness of the reburn process: primary zone fuel type, primary zone stoichiometry, and NO_x level of the gas leaving the primary zone. Table 5-2 indicates that reburn systems have been used with all three fuels: gas, oil, or coal, as the primary zone fuel. The selection of primary zone stoichiometry is influenced by boiler efficiency and corrosion considerations as well as NO_x emissions. Three investigations, Maringo et al. (1987), Maringo and McElroy (1987), and Farazan et al. (1989) indicate that for cyclone-fired coal furnaces the primary zone stoichiometry should not be less than 1.1 in order to avoid corrosion in the cyclone and to assure complete combustion of the primary fuel. Another investigation, McCarthy et al. (1987), states that it is important to minimize excess air in the main burner zone in order to minimize NO_x leaving the primary zone. The NO_x concentration of the gas leaving the primary zone has an effect on the performance of the reburn zone. The NO_x level leaving the reburn zone is lowest when the NO_x level entering the reburn zone is the lowest. However, the percentage reduction of NO_x increases as the NO_x level entering the reburn zone increases.

Reburn Zone

Reburn Zone Fuel. Table 5-3 shows that all three fuels have been used for the reburn fuel. However gas was found to have advantages because it contains no fuel nitrogen, retrofits are generally easier, and burnout can be more successfully accomplished in the limited furnace volume available when gas is the reburn fuel.

Fraction of Reburn Fuel. For tests listed in Table 5-3 the fraction of reburn fuel varied from a very small fraction up to 70%. Maringo and McElroy (1987) and Farzan et al. (1989) showed that NO_x levels decreased with increasing amounts of reburning fuel fraction (up to about 35%). This can be generally attributed to higher values of reburning fuel fraction corresponding to lower reburning zone stoichiometries. Also, for the case of using gas as a reburning fuel, substitution of higher percentages of gas for coal reduced the total nitrogen fuel input to the furnace. Additionally, as the percentage of fuel in the primary zone is decreased, peak temperatures are decreased and thermal NO_x is thereby decreased. Mulholland and Srivastava (1987) found that NO_x emissions decreased with increased fuel staging. They attributed this to NO_x destruction by the reburn process and the reduced overall fuel nitrogen content. McCarthy

Table 5-2
Reburn Experimental Parameters

GENERAL	
Organization	SPECIFIC NAME OF ORGANIZATION THAT CARRIED OUT EXPERIMENTAL MEASUREMENTS
Investigator(s)	AUTHORS OF SPECIFIC REFERENCE
Date (s)	DATES OF REFERENCES ON EXPERIMENTS
OVERALL SYSTEM	
Furnace Type	SCALE OF EXPERIMENTAL COMBUSTION STUDY (LAB., PILOT, FULL SCALE)
Furnace Size	GEOMETRIC DIMENSIONS OF COMBUSTION CHAMBER
(MBTU/hr)	FUEL FIRING CAPACITY IN MILLIONS OF BTU/HR.
Carbon Loss Calc. (Y/N)	WERE MEASUREMENTS/CALCULATIONS CARRIED OUT TO CALCULATE CARBON LOSS?
Heat Flux Change Calc. (Y/N)	WERE EXPERIMENTAL MEASUREMENTS MADE TO DETERMINE THE COMBUSTOR WALL HEAT FLUX
PRIMARY COMBUSTOR	
Fuel Type	SPECIFIC FUEL TYPE (GAS, OIL, OR COAL) IN PRIMARY COMBUSTOR
Varied Fuel (Y/N)	WAS FUEL TYPE VARIED
SR Primary	STOICHIOMETRIC RATIO AT PRIMARY COMBUSTOR EXIT
NOx Primary Exit (3 % O2)	RANGE OF NOX EMISSIONS AT PRIMARY COMBUSTOR EXIT
In-Furnace Species Data (Y/N)	WERE EXPERIMENTAL MEASUREMENTS MADE OF SPECIES CONCENTRATION IN PRIMARY ZONE?
REBURN SECTION	
Reburn Fuel	SPECIFIC FUEL TYPE (GAS, OIL, OR COAL) IN REBURN COMBUSTOR SECTION
% Reburn Fuel	PERCENTAGE OF TOTAL COMBUSTOR ENERGY INPUT IN REBURN COMBUSTOR SECTION
Reburn Fuel Nitrogen Content	RANGE OF FUEL NITROGEN CONTENT OF REBURN FUEL
Fuel Transport Gas	SPECIFIC GAS USED FOR REBURN FUEL TRANSPORT
SR Reburn	STOICHIOMETRIC RATIO AT EXIT OF REBURN ZONE
No. of Reburn Stages	NUMBER OF COMBUSTOR JET STAGES IN REBURN COMBUSTOR SECTION
Reburn Temperature	RANGE OF MEASURED TEMPERATURES IN REBURN COMBUSTOR SECTION
Reburn Residence Time (sec)	RANGE OF GAS RESIDENCE TIME IN REBURN COMBUSTOR SECTION
Jet Mixing Studied (Y/N)	WAS JET MIXING OF REBURN JETS STUDIED IN REBURN ZONE?
In-Furnace Species Data (Y/N)	WERE EXPERIMENTAL MEASUREMENTS MADE OF SPECIES CONCENTRATION IN REBURN ZONE?
BURNOUT ZONE	
SR Exit	STOICHIOMETRIC RATIO AT END OF BURNOUT ZONE OR COMBUSTOR EXIT
NOx Exit (3%O2)	RANGE OF NOX EMISSIONS MEASURED AT COMBUSTOR EXIT
In-Furnace Species Data (Y/N)	WERE EXPERIMENTAL MEASUREMENTS MADE OF SPECIES CONCENTRATION AT COMBUSTOR EXIT?
Reburn Efficiency (%)	PERCENTAGE DECREASE IN NOX LEVEL FROM PRIMARY COMBUSTOR SECTION
NOx Reduction Efficiency (%)	PERCENTAGE DECREASE IN NOX LEVEL FROM BASELINE COMBUSTOR VALUE

Table 5-3, Sheet 1
Reburn Experimental Data Summary

GENERAL					
Organization	Babcock & Wilcox	Ishikawajimi-Harima	Ishikawajimi-Harima	Ishikawajimi-Harima	Ishikawajimi-Harima
Investigator(s)	Farzan and Rogers,	Miyamae, et. al.	Miyamae, et. al.	Miyamae, et. al.	Miyamae, et. al.
	Eckhart, et al.				
Date (s)	1989	1985	1985	1985	1985
OVERALL SYSTEM					
Furnace Type	Pilot Scale	Pilot Scale	Pilot Scale	Pilot Scale	600 MW Steam Gen.
					Wall- fired
Furnace Size	Cyclone Burner	3 x 3 x 10m	3 x 3 x 10m	3 x 4.5 x 11m	-
(MBTU/hr)	up to 6	~ 40	~ 80	~ 60	-
Carbon Loss Calc. (Y/N)	Y	N	N	N	N
Heat Flux Change Calc. (Y/N)	N	N	N	N	N
PRIMARY COMBUSTOR					
Fuel Type	Coal, CWF	Butane	Fuel Oil	Pulverized Coal	Oil(70%)/Coal(30%)
Varied Fuel (Y/N)	Y	N	N	N	N
SR Primary	1.0- 1.2	0.7- 1.3	0.8- 1.2	0.85 - 0.95	0.84- 0.91
NOx Primary Exit (3 % O2)	900- 1200	-	-	-	-
In-Furnace Species Data (Y/N)	N	N	N	N	N
REBURN SECTION					
Reburn Fuel	gas, oil, coal	Butane	Fuel Oil	Pulverized Coal	Oil
% Reburn Fuel	15- 35	5- 18	5- 18	0 -16	0- 10
Reburn Fuel Nitrogen Content	0- 1.5	-	0.02%	1.50%	0.24%
Fuel Transport Gas	air	-	-	Air/ Flue gas	-
SR Reburn	0.85- 0.95	-	-	-	-
No. of Reburn Stages	1	1	1	1	1
Reburn Temperature	-	-	-	-	-
Reburn Residence Time (sec)	0.5- 0.8	-	-	-	-
Jet Mixing Studied (Y/N)	N	N	N	N	N
In-Furnace Species Data (Y/N)	N	N	N	N	N
BURNOUT ZONE					
SR Exit	1.05- 1.2	-	-	-	-
NOx Exit (3%O2)	250- 550	35- 160	30- 95	85- 100	80- 110
In-Furnace Species Data (Y/N)	N	N	N	N	N
Reburn Efficiency (%)	-	-	-	-	-
NOx Reduction Efficiency (%)	up to 57	-	-	-	-

Table 5-3, Sheet 2
Reburn Experimental Data Summary

GENERAL						
Organization	Ishikawajimi-Harima	Hitachi-Babcock	MHI	MHI	MHI	MHI
Investigator(s)	Miyamae, et. al.	Narita, et. al.	Murakami	Takahashi, et al	Takahashi, et al	Takahashi, et al
Date (s)	1985	1987	1985	1982/1981	1982/1981	1982/1981
OVERALL SYSTEM						
Furnace Type	55 MW Steam Gen.	200 MWe Furnace	600 MW	Small Scale	Pilot Scale	Pilot Scale
	Front- fired	Wall- fired	T- fired	Furnace	T-fired	T-fired
Furnace Size	-	-	-	0.8m diam x 2.2m	-	-
(MBTU/hr)	-	-	-	~ 2.5	up to ~ 60	up to ~ 40
Carbon Loss Calc. (Y/N)	Y	Y	Y	N	N	N
Heat Flux Change Calc. (Y/N)	N	N	N	N	N	N
PRIMARY COMBUSTOR						
Fuel Type	Pulverized Coal	Pulverized Coal	Oil/Coal(to 30%)	Propane/Coal	Gas/ Fuel Oil	Pulverized Coal
Varied Fuel (Y/N)	N	Y (5 types)	Y (%coal)	N	Y (6 oils)	N
SR Primary	0.8- 1.05	-	-	-	-	-
NOx Primary Exit (3 % O2)	-	-	-	-	-	-
In-Furnace Species Data (Y/N)	N	N	N	Y	N	N
REBURN SECTION						
Reburn Fuel	Pulverized Coal	Pulverized Coal	Oil	Propane/Coal	Gas/Fuel Oil	Pulverized Coal
% Reburn Fuel	0- 10	-	-	0- 10	0 - ~20	0- ~25
Reburn Fuel Nitrogen Content	2.00%	0.76- 1.71%	-	0/1.0	0- 0.9	-
Fuel Transport Gas	Air	Air	Flue gas	Air	Air	Air
SR Reburn	-	-	-	0.1- 1.4	-	-
No. of Reburn Stages	1	1	1	1	1	1
Reburn Temperature	-	-	-	1650- 2350F	-	-
Reburn Residence Time (sec)	-	-	-	0.1- 0.8	-	-
Jet Mixing Studied (Y/N)	N	N	N	N	N	N
In-Furnace Species Data (Y/N)	N	N	N	Y	N	N
BURNOUT ZONE						
SR Exit	-	-	-	-	1.05- 1.17	1.1- 1.23
NOx Exit (3%O2)	140- 240	180- 260	72- 180	-	-	-
In-Furnace Species Data (Y/N)	N	N	N	Y	Y	Y
Reburn Efficiency (%)	-	-	-	10- 95	-	-
NOx Reduction Efficiency (%)	-	-	-	-	-	-

Table 5-3, Sheet 3
Reburn Experimental Data Summary

GENERAL						
Organization	Riley Stoker	Riley Stoker	Riley Stoker	Acurex/EPA	Acurex/EPA	Acurex/EPA
Investigator(s)	Lisauskas, et al.	Penterson, et al.	Penterson, et al.	Mulholland & Srivastava	Mulholland, et. al.	Mulholland, et. al.
Date (s)	1985	1989	1989	1987	1987/1985	1987/1985
OVERALL SYSTEM						
Furnace Type	Pilot Scale End- fired	Pilot Scale- IGT	Pilot Scale- MSW	Package Boiler Simulator	Package Boiler Simulator	Package Boiler Simulator
Furnace Size	18 x 18 x 60ft	4.5 x 3 x 14ft	3 x 11.75 x 17ft	0.6m diam x 3 m	0.6m diam x 2.3m	0.6m diam x 2.3m
(MBTU/hr)	100	1.7	3	~ 2	~ 2- 2.7	~ 2
Carbon Loss Calc. (Y/N)	N	N	N	N (CO data)	N	N
Heat Flux Change Calc. (Y/N)	N	N	N	N	N	N
PRIMARY COMBUSTOR						
Fuel Type	Pulverized Coal	Simulated MSW	MSW	Natural Gas	Natural Gas	Fuel Oil
Varied Fuel (Y/N)	Y (4 types)	N	N	N	N	Y (light, heavy)
SR Primary	-	-	0.95- 1.31	0.78	0.9- 1.2	0.95- 1.16
NOx Primary Exit (3 % O2)	-	100- 300	120- 165	-	43- 430	43-430
In-Furnace Species Data (Y/N)	N	N	N	N	Y	Y
REBURN SECTION						
Reburn Fuel	Pulverized Coal	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Fuel Oil
% Reburn Fuel	10- 28	7- >30	7- 15	0- 35	0- 37	0- 29
Reburn Fuel Nitrogen Content	1.03- 1.44%	-	-	0	0- 1.0%	0- 0.5%
Fuel Transport Gas	Air	-	-	-	-	-
SR Reburn	0.75- 1.0	0.6- 1.22	0.6- 1.25	0.65- 1.1	0.7- 1.1	0.8- 1.1
No. of Reburn Stages	1	1	1	1	1	1
Reburn Temperature	-	1950- 2400	-	-	2000- 2400F	2000- 2400F
Reburn Residence Time (sec)	-	1- 5.2	1.2- 5.2	-	0- 0.4	0.1- 0.4
Jet Mixing Studied (Y/N)	N	N	N	N	Y (injection pts)	N
In-Furnace Species Data (Y/N)	N	N	N	N	Y	Y
BURNOUT ZONE						
SR Exit	1.2	-	-	1.15	1.0- 1.3	1.0- 1.3
NOx Exit (3%O2)	175- 400	70- 180	71- 142	140- 275	-	-
In-Furnace Species Data (Y/N)	N	N	N	N	Y	Y
Reburn Efficiency (%)	-	-	-	-	~0- 75%	~0- 40%
NOx Reduction Efficiency (%)	up to 75	up to 70	up to 50	up to 50	-	-

Table 5-3, Sheet 4
Reburn Experimental Data Summary

GENERAL						
Organization	Acurex/EPA	Acurex	Acurex	EER	EER	EER
Investigator(s)	Mulholland, et. al.	Kelly, et al	Brown & Kuby	McCarthy, et. al.	Green, et. al.	Clark,et. al.
				Overmoe, et al		Chen, et. al.
Date (s)	1987/1985	1985/1982	1985	1987/1985	1985/1984	1982
OVERALL SYSTEM						
Furnace Type	North American	Lab Subscale	Subscale Combustor-	Pilot Scale Comb	Lab Scale Comb	Lab Scale Comb.
	Boiler	Combustor	Engine Exh. Simulator	(Downfired)	(Downfired)	(Downfired)
Furnace Size	-	8 in diam x 72in	4 to 6 in duct	4 x 4 x 26 ft	6in diam x 4ft	6 in diam x 4 ft
(MBTU/hr)	~ 2.5	~ 0.055	~ 0.1	~ 10	up to 0.083	~ 0.07
Carbon Loss Calc. (Y/N)	N	Y	Y	Y	N	N
Heat Flux Change Calc. (Y/N)	N	N	N	N	N	N
PRIMARY COMBUSTOR						
Fuel Type	Fuel Oil	Pulverized Coal	Gas	Gas/Oil/Coal	Gas/Coal	Gas/Pulverized Coal
Varied Fuel (Y/N)	Y (No. 2, 5)	Y (5 types)	N	Y	Y	Y (2 Coals)
SR Primary	-	0.9- 1.2	-	0.9- 1.2	1.5- 1.3	1.05- 1.4
NOx Primary Exit (3 % O2)	-	-	430- 2600	~ 200- 1000	-	-
In-Furnace Species Data (Y/N)	N	Y	Y	Y	N	N
REBURN SECTION						
Reburn Fuel	Natural Gas	Natural Gas/ Coal	Gas	Gas/Oil/Coal	Gas/Coal	Propane/Coal
% Reburn Fuel	0- 20	25- 50	10- 38	0- 30	0- 36	-
Reburn Fuel Nitrogen Content	0- 1.3%	0.7- 1.5%	-	1.17- 1.94	0.68- 1.88	0- 1.67
Fuel Transport Gas	-	-	-	Air/Flue Gas	Air/N2	Air
SR Reburn	0.88- 1.05	0.6- 1.2	0.9- 1.05	0.7- 1.0	0.7- 1.25	0.6- 1.[illegible]
No. of Reburn Stages	1	1	1	1	1	1
Reburn Temperature	~ 2300F	~ 2300-2600F	-	~2550F	~2200-2800F	-
Reburn Residence Time (sec)	~ 0.2	0.5- 1.6	0.25- 0.3	0.6- 1.0	0.14- 0.75	-
Jet Mixing Studied (Y/N)	Y (injection pts)	N	N	Y	Y	N
In-Furnace Species Data (Y/N)	N	Y	Y	Y	Y	N
BURNOUT ZONE						
SR Exit	-	1.2	-	1.1- 1.35	~ 1.25	1.05- 1.3
NOx Exit (3%O2)	-	up to 860	-	~ 200- 500	-	-
In-Furnace Species Data (Y/N)	N	Y	Y	Y	N	Y
Reburn Efficiency (%)	~ 0- 50%	-	-	up to 50	up to 70	up to 60
NOx Reduction Efficiency (%)		up to 70	up to 70	-	-	_

Table 5-3, Sheet 5
Reburn Experimental Data Summary

GENERAL						
Organization	EER	ENEL	KVB	KVB	KVB	KVB
Investigator(s)	Clark,et. al.	Baldacci, et. al	Bortz &	Yang, et. al.	Yang, et. al.	Yang, et . al.
	Chen, et. al.		Offen (EPRI)			
Date (s)	1982	1988	1987	1985	1984	1984
OVERALL SYSTEM						
Furnace Type	Lab Scale	Lab Scale	Lab Scale Comb	Lab Scale Comb	Lab Scale Comb	Lab Scale Comb
	Reactor	Reactor	(Downfired)	(Upfired)		(Cement Kiln Sim.)
Furnace Size	-	-	18 in diam	14 in diam x 7 ft	8 in diam x 7 ft	5 in diam x 12 ft
(MBTU/hr)	-	0.2	0.5	up to 0.25	0.13	0.17
Carbon Loss Calc. (Y/N)	N	N	N	N	N	N
Heat Flux Change Calc. (Y/N)	N	N	N	N	N	N
PRIMARY COMBUSTOR						
Fuel Type	Gas	Heavy Fuel Oil	Pulverized Coal	Natural Gas	Natural Gas	Natural Gas/ Coal
Varied Fuel (Y/N)	N	N	N	N	N	N
SR Primary	1.1	1.0- 1.115	0.85- 1.2	0.4- 1.2	0.9- 1.7	1- 1.23
NOx Primary Exit (3 % O2)	up to ~ 500	950	90- 500	-	-	
In-Furnace Species Data (Y/N)	N	N	N	N	N	N
REBURN SECTION						
Reburn Fuel	Methane	GPL	Gas (3 Types)	Natural Gas	Natural Gas	Coal
% Reburn Fuel	-	5- 30	0- 20	up to 70	0- 70	10- 60
Reburn Fuel Nitrogen Content	0- 0.5	-	-	-	-	0.84
Fuel Transport Gas	N2	-	-	-	-	Air
SR Reburn	0.75- 1.25	0.8- 1.0	0.8- 1.05	0.5- 1.15	0.5- 1.15	0.7- 1.2
No. of Reburn Stages	1	1	1	1	1	1
Reburn Temperature	~2100-3100F	> 2400F	2200- 2400F	-	-	-
Reburn Residence Time (sec)	-	0.1- 0.4	0.25- 0.5	-	-	-
Jet Mixing Studied (Y/N)	N	N	N	Y (varied inj. pt.)	Y(varied inj. pt.)	N
In-Furnace Species Data (Y/N)	Y	N	N	N	N	N
BURNOUT ZONE						
SR Exit	~ 1.2	1.02- 1.15	1.2	-	~ 1.15	~ 1.22
NOx Exit (3%O2)	-	-	~ 150- 500	-	-	-
In-Furnace Species Data (Y/N)	Y	N	Y	Y	N	N
Reburn Efficiency (%)	up to 50	-	-	-	-	-
NOx Reduction Efficiency (%)	-	up to 56	-	up to 90	up to 90	up to 90

Table 5-3, Sheet 6
Reburn Experimental Data Summary

Organization	KVB	Hitachi Zosen	Hitachi Zosen	IFRF	MIT	MIT
Investigator(s)	Radak, et. al.	Okigami, et. al.	Okigami, et. al.	Knill, et al.	Toqan, et. al.	Farmayan,
	(w/ SCE)					
Date (s)	1982	1985	1985	1988, 1989	1987	1985
OVERALL SYSTEM						
Furnace Type	175 MW Steam Gen	Lab Scale	Pilot Scale	Lab Scale	Pilot Scale	Pilot Scale
	Wall- fired	Combustor	Combustor	Plug Flow	Combustor	Combustor
Furnace Size	-	Cylindrical	3.5 x5 x12.5m	0.3m diam x 1m	1.2 x1.2 x4.5m	1.2 x1.2 x4.5m
(MBTU/hr)	-	~ 5	~ 25	-	~ 5	~ 5
Carbon Loss Calc. (Y/N)	N	N	Y	N	N	N
Heat Flux Change Calc. (Y/N)	N	N	N	N	N	N
PRIMARY COMBUSTOR						
Fuel Type	Natural Gas/Oil	Pulverized Coal	Pulverized Coal	Natural Gas	No. 6 Oil	Natural Gas
Varied Fuel (Y/N)	N	N	Y (2 Types)	N	N	N
SR Primary	-	~ 1	-	1.0- 1.15	-	0.67- 1.18
NOx Primary Exit (3 % O2)	-	-	-	200- 600	~ 350	-
In-Furnace Species Data (Y/N)	N	N	N	Y	N	Y
REBURN SECTION						
Reburn Fuel	Natural Gas	Pulverized Coal	Pulverized Coal	Pulverized Coal	Natural Gas	Natural Gas
% Reburn Fuel	0- 34	-	-	0- 30	33	0- 50
Reburn Fuel Nitrogen Content	-	1.8	1.59- 2.0	1.7- 1.8	-	-
Fuel Transport Gas	-	Air	Air	Nitrogen	-	-
SR Reburn	0.76- 0.81	-	-	0.8- 1.02	0.9	0.67- 1.02
No. of Reburn Stages	1	1	1	1	1	1
Reburn Temperature	-	-	-	2000- 2550F	2400- 2700F	-
Reburn Residence Time (sec)	-	-	-	0.1- 1.0	-	-
Jet Mixing Studied (Y/N)	N	N	N	Y	N	Y (jet inj. angle
In-Furnace Species Data (Y/N)	N	N	N	Y	N	Y
BURNOUT ZONE						
SR Exit	-	-	-	-	-	1.05
NOx Exit (3%O2)	100- 180	~ 100- 400	~ 120- 180	40- 400	-	-
In-Furnace Species Data (Y/N)	N	N	N	Y	N	Y
Reburn Efficiency (%)	-	-	-	-	up to 20	-
NOx Reduction Efficiency (%)	-	-	-	-	-	up to 90

et al. (1987) stated that if flue gas recirculation is used, reburn fuel fraction should be set at 20%. If flue gas recirculation is not used, the reburn fuel fraction should be set at approximately 30%.

Maringo et al. (1987) stated that for large cyclone combustor designs, the reburn fuel fraction should range between 15 and 25%. From this range of experience, the authors concluded that 25% reburn fuel would represent a good initial choice.

Reburn Fuel Nitrogen Content. As one might expect, this parameter has a significant effect on NOx emissions. The following are specific comments:

- McCarthy et al. (1987) stated that for highest reburning efficiency, a nitrogen-free reburn fuel should be used.
- Mulholland et al. (1987) noted that NO_x reduction via reburning is strongly dependent on fuel nitrogen. They concluded that NO_x reduction is adversely influenced by the presence of bound nitrogen in the reburn fuel, especially in cases where the primary zone NO_x is low.
- Green et al. (1984, 1985) found that nitrogen-free reburn fuels were the most effective for NO_X reduction.

Reburn Fuel Transport Gas/Mixing Medium. Experimental work by several investigators led to the following results:

- Green et al. (1984, 1985) stated that an inert reburning fuel transport medium (oxygen free) is desirable since less reburning fuel is required to attain optimum stoichiometry. Overmoe et al. (1985) stated that one should minimize the available transport oxygen and in particular flue gas recirculation should be used as a transport medium, if possible. McCarthy et al. (1987) concluded that coal fired systems, if feasible, should use flue gas recirculation as the reburning coal transport medium (with approximately 20% reburn fuel). However, if air must be used for the reburning fuel transport, they stated that the reburning fuel ratio should be increased to 30%.

- Takahashi et al. (1981) noted that the use of flue gas recirculation in the reburn zone lowers the NO_x emissions for the following reasons:

  1) It improves the mixing of the reburn fuel into the main combustion gas stream.
  2) It causes the production of radicals (C_nH_m) that improve the NO_x removal process in the reburn zone.
  3) The water contained in the recirculated flue gas has the effect of suppressing the production of soot through a water gas reaction, resulting in a decreased amount of smoke, dust, etc.

- Maringo and McElroy (1987) reported that adding flue gas recirculation flow to the reburn zone burners improved the NO_x reduction capability of their pilot scale facility. Specifically, with an addition of just 10% flue gas recirculation, they were able to show a NO_x reduction improvement of about 13% across a wide range of natural gas reburn fuel inputs.

Stoichiometric Ratio in the Reburn Zone. Most investigators agree that the stoichiometric ratio in the reburn zone is one of the most important parameters for the reburn efficiency of a combustion system. This value was varied over a wide range for the tests listed in the data summary. Some of the comments regarding this variable are as follows:

- Toqan et al. (1987) found an optimum stoichiometric ratio of 0.77 based on a theoretical model; however, based on their experiments 0.91 was optimum.
- Farmayan et al. (1985) found that optimum NO_x reduction was achieved with a reburn zone stoichiometric ratio between 0.77 and 0.83.
- Mulholland et al. (1987) stated that NO_x reduction via reburning is strongly dependent on reburn stoichiometry.
- Maringo et al. (1987) postulated that, for large-scale systems, the reburn zone in a cyclone boiler should operate at a stoichiometric ratio of 0.85-0.95. This conclusion was based on maximum NO_x reduction from laboratory scale studies.
- Miyamae et al. (1985) noted that one of the dominant variables controlling NO_x reduction by reburning is the stoichiometry in the reburn zone.
- Lisauskas et al. (1985) showed a general decrease in exit NO_x as reburn zone stoichiometry was decreased from approximately 1.1 to 0.65.
- Green et al. (1984, 1985) concluded that the reburning zone stoichiometry was optimized at 0.9.
- Takahashi et al. (1981) stated that NO_x decomposition rate falls off rapidly after the reburn zone stoichiometric ratio becomes greater than 0.9. Again, it should be noted that this conclusion is based on the experimental results from small scale experiments.
- Eckhart et al. (1989) achieved maximum NO_x emissions reduction at reburn zone stoichiometries of about 0.85 in their pilot scale experiments.

Reburn Zone Temperature. The general consensus of the experimental investigators on the subject of temperature in the reburn zone is that the effectiveness of the reburn process increases with increasing temperature. As shown in the experimental data summary, a wide range of temperatures were reported for the reburn zone. The following comments apply to this parameter:

- Takahashi et al. (1981) stated that the reburn temperature should be at least 1650 °F and that temperatures higher than 2350°F are preferred.
- Green et al. (1984) concluded that the reduction of NO_x increases with increasing temperature in the range from 2400 to 2900 °F.

- McCarthy et al. (1987) and Overmoe et al. (1985) stated that the reburning fuel should be injected into as hot a furnace environment as possible.

From this limited data, it can be concluded that the gas temperatures in the reburn zone should be as high as possible, without creating thermal NO_x.

Reburn Zone Residence Time. The reburn experimental results indicate that the residence time in the reburn zone varied over a wide range, from 0.1 to 1 second. Despite this variation in residence times, there is general agreement that this parameter is important for reburn zone design. Some comments regarding this variable are as follows:

- Maringo and McElroy (1987) varied the reburn zone residence time from 0.5 to 0.8 seconds and found that longer residence time provided the greatest NO_X reduction.
- Mulholland et al. (1987) concluded that NO_x reduction increased with reburn zone residence time, with more rapid changes after 50 ms, and leveling off at 300 to 400 ms. Mulholland and Hall (1985) noted that there was a practical design constraint of 500 ms or less residence time in the reburn zone.
- McCarthy et al. (1987) and Overmoe et al. (1985) concluded that one should maximize the reburn zone residence time. Green et al. (1984, 1985) stated that this variable has a strong impact on NO_x reduction efficiency, increasing with time (from a range of 100-750 ms).
- Maringo et al. (1987) postulated that, based on pilot and field scale tests, a 50-60% reduction in NO_x could be achieved at residence times greater than 450 ms.
- Lisauskas et al. (1985) found that NO_x emissions decreased as residence time increased.

Thus, from the general consensus, it appears that a reburn zone residence time of at least 500 ms is desirable, with longer times desirable, if practical. The difficulty of obtaining an accurate value, or interpretation, of residence time in practical sized combustors where the flow is generally not of the one dimensional plug flow type should be pointed out. This point was made in the pilot plant study of Maringo and McElroy (1987), where they presented some serious questions regarding the accuracy of their residence time calculations. In practice, detailed measurements of furnace gas velocity and direction or other types of residence time determination are highly desirable.

For the design of a full-scale reburn system, Borio et al. (1989) stated that the key design criteria for the reburn system include:

- Inject reburn fuel into as high a temperature zone as possible, commensurate with releasing all fuel-bound nitrogen upstream of the reburn zone.
- Maintain average stoichiometry between 0.90 and 0.95.
- Permit a small amount of O_2 to promote the formation of OH and H radicals.
- Maintain the residence time between 0.5 and 0.7 seconds.

- Maximize entrainment, mixing, and dispersion of reburn fuel.
- Avoid direct fuel impingement on boiler walls.
- Minimize the number of required boiler penetrations.
- Locate fuel injection nozzles to minimize boiler/structural steel modifications.
- Provide for maximum flexibility of reburn fuel jet direction and flow rates.
- Provide a fuel flow rate control system with automatic load following capability
- Provide safeguards for fail-safe operation.

Reburn Zone Mixing. Since many of the experimental studies listed in Table 5-3 were conducted in small scale facilities, reburn zone mixing was not studied as a separate design entity in a majority of the experiments. However, mixing was recognized as an important reburn design variable during several investigations. The following comments emphasize this point:

- Maringo and McElroy (1987) varied the mixing and residence time in the reburn zone by moving overfire air ports and varying spin vanes in the reburn zone burners. They found that lower swirl from the reburn burner enhanced the NO_x reduction efficiency of the system.
- Mulholland et al. (1987) stated that uniformity of the reburn zone stoichiometry should be important for optimizing NO_x reduction. They varied injection geometry and location via a reburn fuel boom inserted in the combustor reburn section. However, due to the existence of large scale turbulent structures in their experimental apparatus, the reburn fuel injection design did not influence reburning effectiveness.
- McCarthy et al. (1987) found that when recirculated flue gas is the transport medium, the reburn fuel should be injected with jet penetration greater than 70% of the furnace depth and coverage of the furnace cross section should be thorough. They also noted that if air must be used for the reburning fuel transport, one should decrease the mixing rate of the reburning jets. Overmoe et al. (1985) and Green et al. (1984, 1985) stated that rapid mixing of the reburn fuel led to more effective NO_x reduction.
- Farmayan et al. (1985) stated that the mode of reburn fuel injection was a principal variable in their experimental reburn systems.

It was concluded that the mixing process had great importance in the design of commercial reburn system. For this reason isothermal flow modeling studies reported by Borio et al. (1989) were conducted for the design of the reburn system for this project.

Burnout Zone

Key parameters in this zone are:

- Stoichiometric ratio
- Temperature
- Residence time
- Jet mixing

Although this zone is an important part of a practical reburn combustion system, very little general information was found in the literature reviewed (Table 5-3). One exception was Knill (1987) who noted that the residence time in the burnout zone must be sufficient for ensuring complete fuel burnout. He concluded that this should not be a problem in gas flames, but in coal flames char burnout may be affected by the size of this zone.

For the design of a full-scale reburn system Borio et al. (1989) stated that the key design criteria for the burnout zone include:

- The injection of burnout air in as low a temperature zone as possible commensurate with obtaining fuel burnout before entering the first convective surface.
- Provision for rapid mixing of air to minimize pockets of unburned fuel
- The avoidance of direct air impingement on furnace walls
- The minimization of final excess oxygen commensurate with obtaining good fuel burnout
- Provision for a residence time of 0.6 to 0.8 seconds.
- Minimization of boiler penetrations while providing maximum flexibility for air jet direction and velocity.

6

DESCRIPTION OF THE HOST UNIT

The Ohio Edison System's Niles Plant is located in Northeastern Ohio on the southwest border of the city of Niles, Weathersfield Township, Trumbull County. The plant occupies 130 acres along the southern bank of the Mahoning River. The main power plant structure covers an area of approximately 166 feet* by 200 feet and consists of two cyclone coal-fired boilers and steam turbine generating units. Approximate site elevation is 870 feet above sea level.

Both units were placed in commercial operation in 1954. Steam turbine conditions are 1450 psig, 1000°F main steam and 384 psig, 1000°F reheat steam. The original design rated gross capacity for each steam turbine was 125 megawatts (MW). Effective January 1985, the demonstrated capacity for each unit was decreased to 108 MW net, which is equivalent to approximately 115 MW gross. The unit capacity rating decrease from the original design of 125 MW to 115 MW was necessitated by continual combustion problems associated with operation of the cyclone-fired boilers.

At low loads, proper slag tap flow is a concern on these cyclone boilers. Any operating conditions that cause reduced lower furnace temperatures can result in poor slag tap flow. Loads below 55 MW net are possible under normal operating conditions. However, operation is reduced to three cyclones in service below approximately 75 MW net. In the event only three cyclones are operating and a second cyclone is forced out-of service, unacceptable steam temperature swings can occur.

The boilers burn primarily high sulfur bituminous coal. They are pressurized radiant furnaces, natural circulation, reheat type boilers with four (4) 9 feet by 12 feet cyclone burners on the front wall and a primary and secondary furnace. The back wall of the secondary furnace has studded waterwall tubes which are coated with refractory to provide sufficient flue gas temperatures in the back passes of the boiler to maintain steam temperatures. Boiler design steam conditions at the turbine governor valves wide-open design point are 885,000 lb/hr, 1650 psig and 1000°F. A side elevation of the boiler is shown in Figure 6-1. Boiler data and operations data are given in Table 6-1.

* For those more familiar with metric units, see the conversion table on Page v.

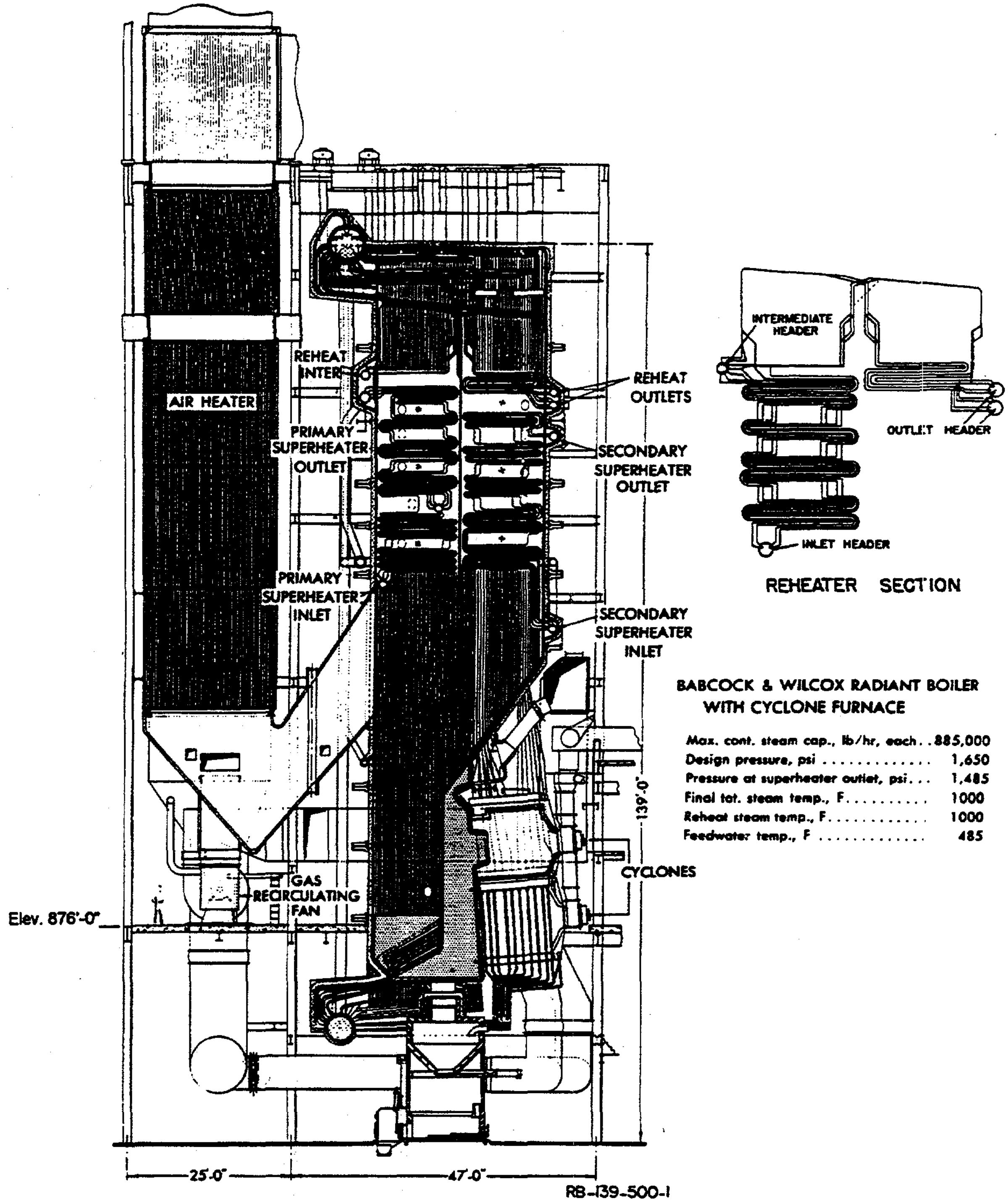


Figure 6-1
Ohio Edison Niles Unit No. 1

Table 6-1
Description of Host Boiler: Niles Unit No. 1

Utility	Ohio Edison Company
Unit Identification	Niles Unit No. 1
Boiler Type	Cyclone Fired, Natural Circulation, Reheat
Manufacturer	Babcock & Wilcox
Date in Service	January 1, 1954
Boiler Nameplate Rating	125 MW Design Capacity (Turbine Generator)
Boiler Steam Conditions	1000°F, 1650 PSIG
Main Steam Flow	885,000 lb/hr
Main Steam Conditions	1000°F, 1450 PSIG
Reheat Steam Conditions	1000°F, 384 PSIG
Net Heat Rate	9,465 Btu/NKWH (1993)
Number of Cyclones	4
Coal Crusher Manufacturer	Pennsylvania Crusher
Total Heat Input @ Rated Capacity	1,199 mmBtu/Hr (Design Coal)
Heat Release	86,000 Btu/Sq. Ft./Hr.
Furnace Width	36′-0″
Gas Temperature Leaving Air Heaters	270°F
Soot Blowers	18 Copes-Vulcan, Service Air
Ash Removal	Pneumatic Transport From Air Heater and ESP Hoppers
Air Heater	Babcock & Wilcox Tubular
Equivalent Availability	84.86% (1993)
Unit Capacity Factor	68.61% (1993)
Boiler Design Efficiency	90.3%
Boiler Actual Efficiency	87.81% (1993)

Four (4) ceramic-extractive oxygen analyzers were originally installed across the back wall of the secondary furnace at the turbine floor level. Each extractive sample probe was located in-line with one of the cyclones. Because the combustion gases remain stratified as they flow through the furnace, each oxygen analyzer provided an indication of the oxygen level resulting from combustion from one cyclone. Therefore, the analyzers could be used to indicate relative balance of combustion air between cyclones and were used to roughly tune the fuel-to-air ratios. The fuel flow rate is determined by volumetric coal feeders.

The original oxygen analyzers plugged with slag frequently and, as a result, provided erroneous readings. The analyzers were never integrated into the boiler control system. Adjustments could provide short-term optimized conditions, but balance of the combustion air between cyclones was not maintained. Due to these problems, the analyzers were removed in October 1992 and new zirconium oxide fuel cell type oxygen analyzers were installed at the air heater inlet.

Each boiler has an electrostatic precipitator (ESP). These were installed in 1981. The ESP's have sufficient capacity to normally operate with only three of their five fields activated. ESP design features are given in Table 6-2. The boilers originally had multi-cone type mechanical dust collectors. Flue gases from each boiler are exhausted to a 393 foot chimney which contains two 11 foot diameter steel-lined flues, each with a design capacity of 330,189 cubic feet per minute. Two 300 foot exhaust stacks connected to the main plant structure were decommissioned in 1981 after the ESP's were installed.

Table 6-2
Description of Electrostatic Precipitator at Niles Unit No. 1

Manufacturer	Wheelabrator-Frye
Installation Date	1981
Number of Fields	5
Collection Surface, ft^2	278,168
Specific Collection Area, ft^2/1000 acfm	520
Design Gas Temperature, °F	270
Velocity through Precipitator, ft/sec	<4.5
Efficiency, percent	99.0
Method of Ash Removal	Dry Pneumatic
Ash Collection and Storage system	Pneumatic Transport to Wet System and Pumped to Pond

7

REBURN SYSTEM DESIGN

Flow Modeling and Reburn System Conceptual Design

Reburn accomplishes in-furnace reduction of NO_x by creating a reducing zone downstream of the primary combustor by a second introduction of fuel as shown schematically in Figure 7-1. The reducing zone creates intermediate chemical compounds composed of carbon, hydrogen, oxygen, and nitrogen which subsequently react with NO_x formed in the primary combustion zone to convert NO_x into the desired final product, molecular nitrogen. Unburned fuel leaving the reburn zone is burned to completion by air introduced in the burnout zone.

This section describes the flow modeling studies and the design of the original reburn system. Following parametric testing of the original system, a modified reburn system was developed. The design basis and equipment design for the modified reburn system are discussed in Section 11.

The effectiveness of reburn for performing the reburn chemical reactions and burnout of the reburn fuel depends upon good mixing of the reburn fuel with the NO_x-containing gases and good mixing of the burnout air with the unburned combustibles leaving the reburn zone. To assist in the design of the reburn system, an isothermal flow model study of the unit was performed. The specific tasks of the modeling effort were:

1. Construct a 1/9 scale isothermal flow model of Ohio Edison's Niles Station Unit No. 1.
2. Using the flow model, map the aerodynamic flow fields within the furnace in its existing baseline configuration.
3. Develop and evaluate potential reburn fuel and burnout air injection system configurations and operating parameters, based on the results of the baseline aerodynamic characterizations, ideal reburn system operating conditions, and the geometric/physical constraints imposed by the unit.
4. Recommend reburn fuel and burnout air injection system designs and operating condition.

Experimental Test Program

The flow modeling was performed in the one-ninth scale model of the Niles Unit shown in Figure 7-2. The model, constructed primarily of clear plastic, encompassed the entire furnace from the cyclone combustors to the vertical furnace outlet plane. The cyclone combustors were

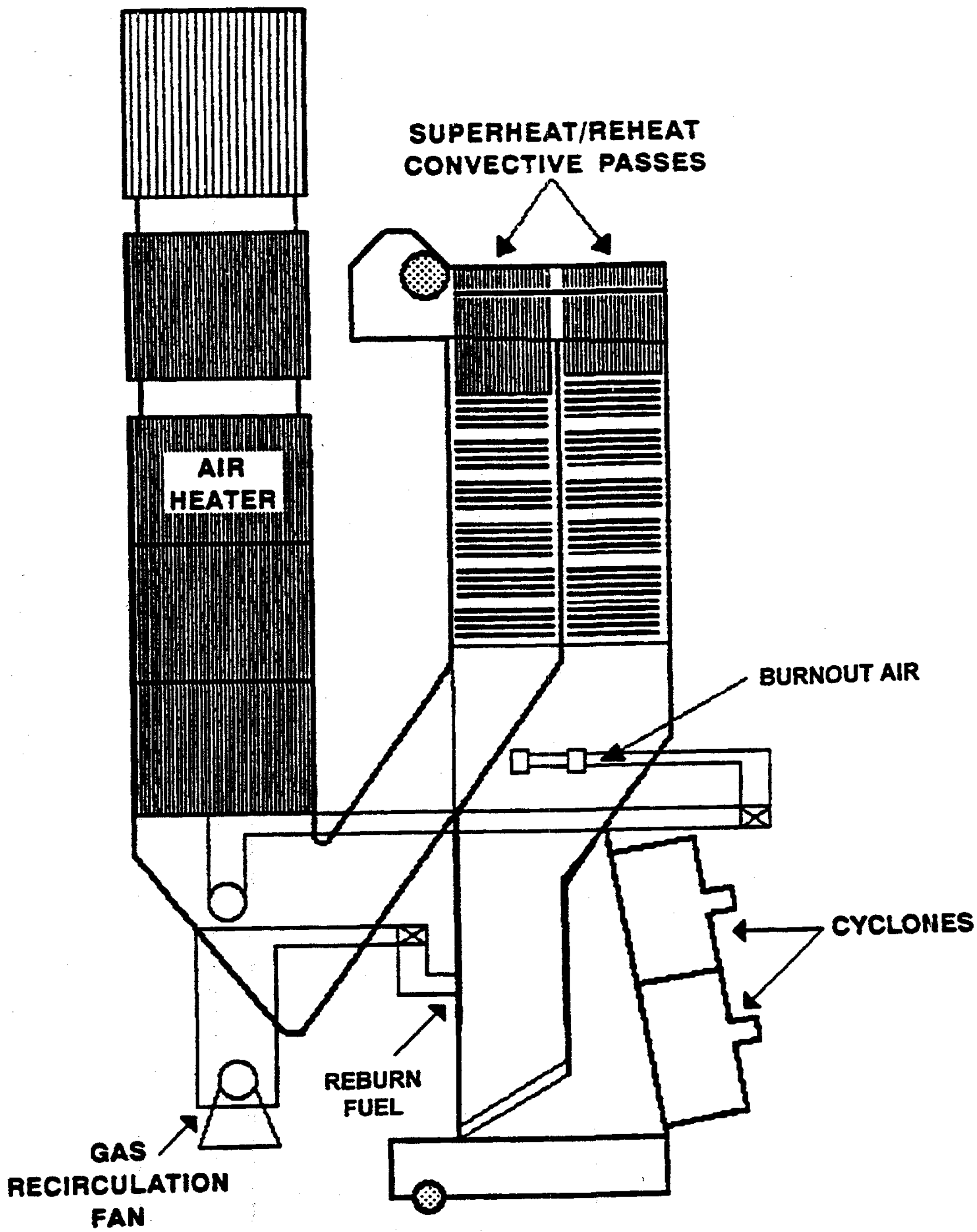


Figure 7-1
Schematic of the Ohio Edison Reburn Process

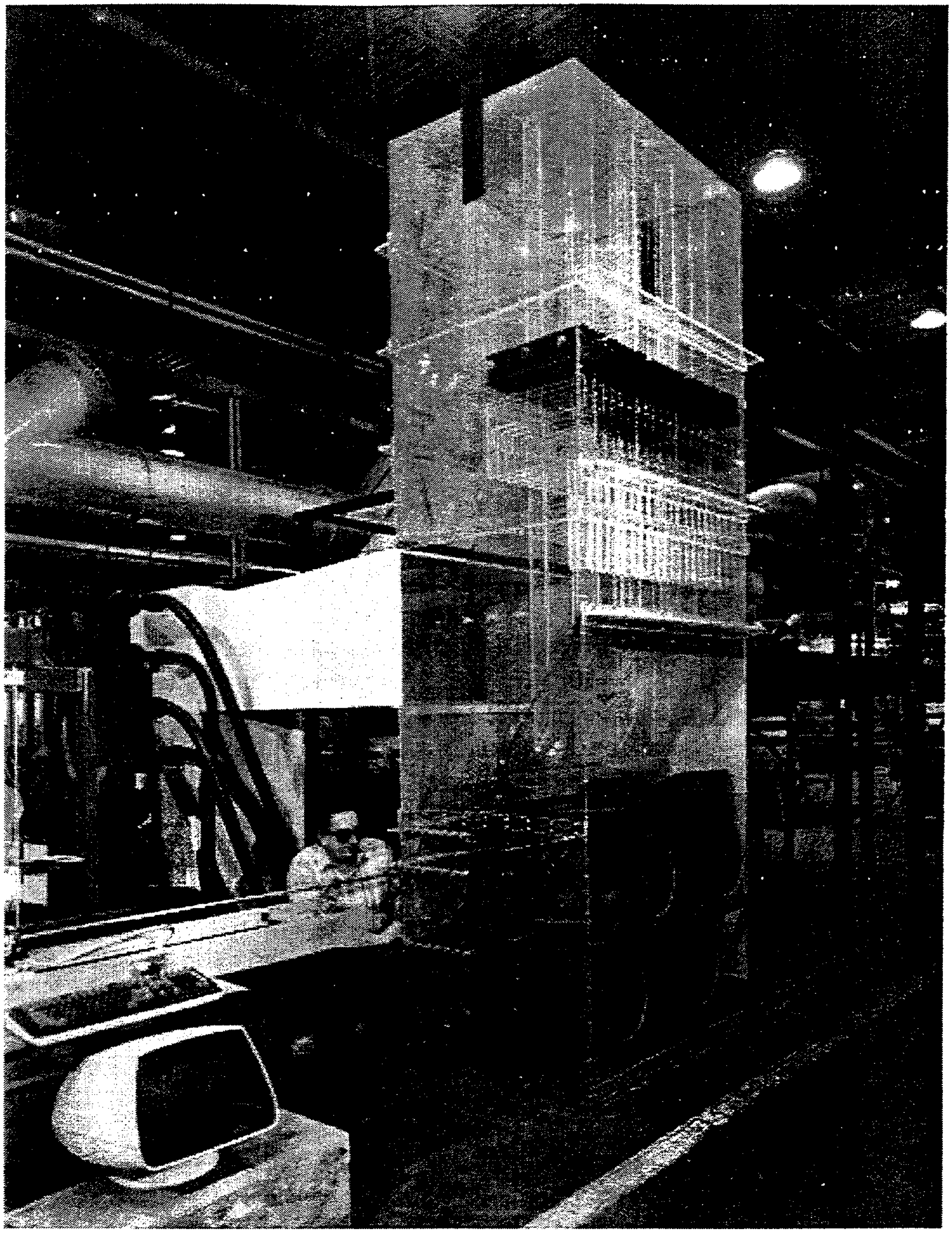


Figure 7-2
One-ninth Scale Flow Model of Niles Unit No. 1

designed to produce the correct swirl and momentum (axial and tangential) entering the primary furnace. Upper furnace radiant and convective heat transfer surfaces were also modeled. A header system fed by a high pressure blower controlled the introduction of smoke or tracer gas to any one or a combination of reburn fuel or burnout air injection nozzles. Flue gas flow through the model was simulated by drawing air through it with a large induced draft fan.

An initial series of isothermal flow modeling tests characterized the baseline gas flow characteristics of the boiler. Following the establishment of the baseline reference data, flow modeling of the reburn system consisted of two screening level tests and a final configuration characterization test for both the fuel and burnout air:

- Screening Level 1 - Flow visualization (with smoke) of a large number of reburn fuel/burnout air injector configurations.
- Screening Level 2 - Mixing study tests on best configuration candidates from Level 1.
- Level 3 - Final injection configurations based on three-dimensional analysis.

In Screening Level 1, smoke flow visualization tests were performed for each candidate injection system at simulated full and 70% load furnace operating conditions. Each injection configuration was evaluated at three injection velocities, three tilts, and a number of yaws. After initial selection of the best injection configurations, Screening Level 2 consisted of methane tracer gas injection tests with concentrations measured by a laser absorption spectrophotometer. Final injection configurations were determined from results of detailed velocity profile measurements using three dimensional (five-hole pitot tube) analysis techniques. Details of the instrumentation used to carry out these measurements are given by Anderson et al. (1986).

Test Results. Baseline furnace velocity fields were measured at Test Planes TP1 through TP5 shown on Figure 7-3. Data were obtained under flow conditions simulating boiler operation at 100% and 70% MCR. Of particular interest for the design of the injectors is the bulk flue gas flow field at the entrance to the reburn zone and burnout zone. Profiles for these planes, TP1 and TP4, are shown in Figures 7-4 and 7-5. Test Plane 1 is characterized by two high velocity areas along the rear wall of the boiler, corresponding to the flow originating from the two lower cyclones. The outlet from the lower cyclones is partially below the dividing wall. As a consequence, a large portion of the gases exiting these cyclones passes unimpeded under the division wall into the secondary furnace.

At Test Plane 4 slightly higher velocities (than average) were found along the rear wall. The side-to-side velocity distribution at this plane shows more flow along the right side of the unit than the left. The cause is uncertain, but it is speculated that it is a function of swirl induced by the cyclones. The side-to-side velocity distribution is more uniform at Test Plane 5.

Fourteen reburn fuel injector configurations were evaluated at three different yaws in the first reburn fuel injector screening test series. Simulated injection velocities ranging from 100 ft/sec to 300 ft/sec were evaluated. Reburn fuel injection nozzle diameters for these velocities and

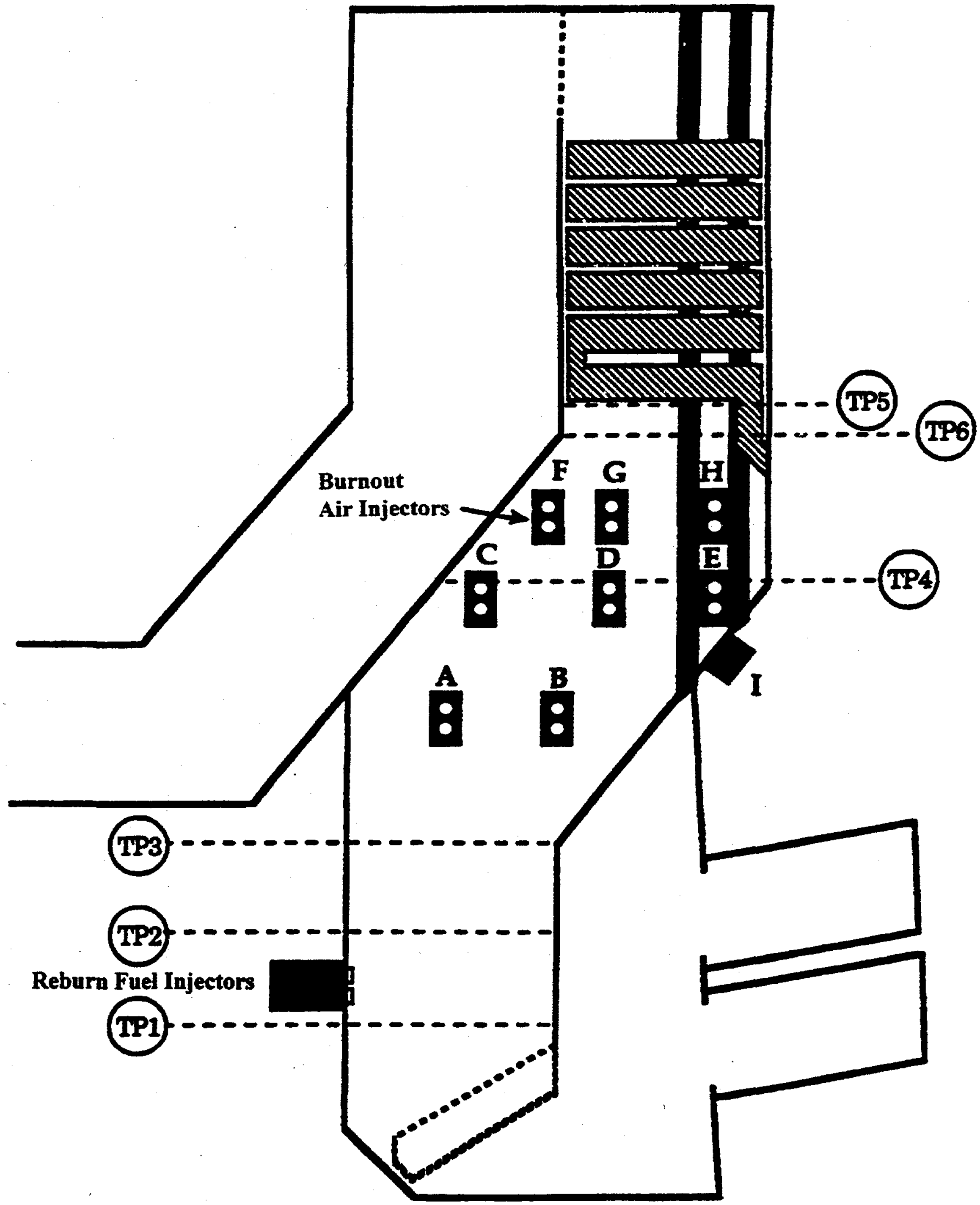


Figure 7-3
Test Plane and Injector Locations

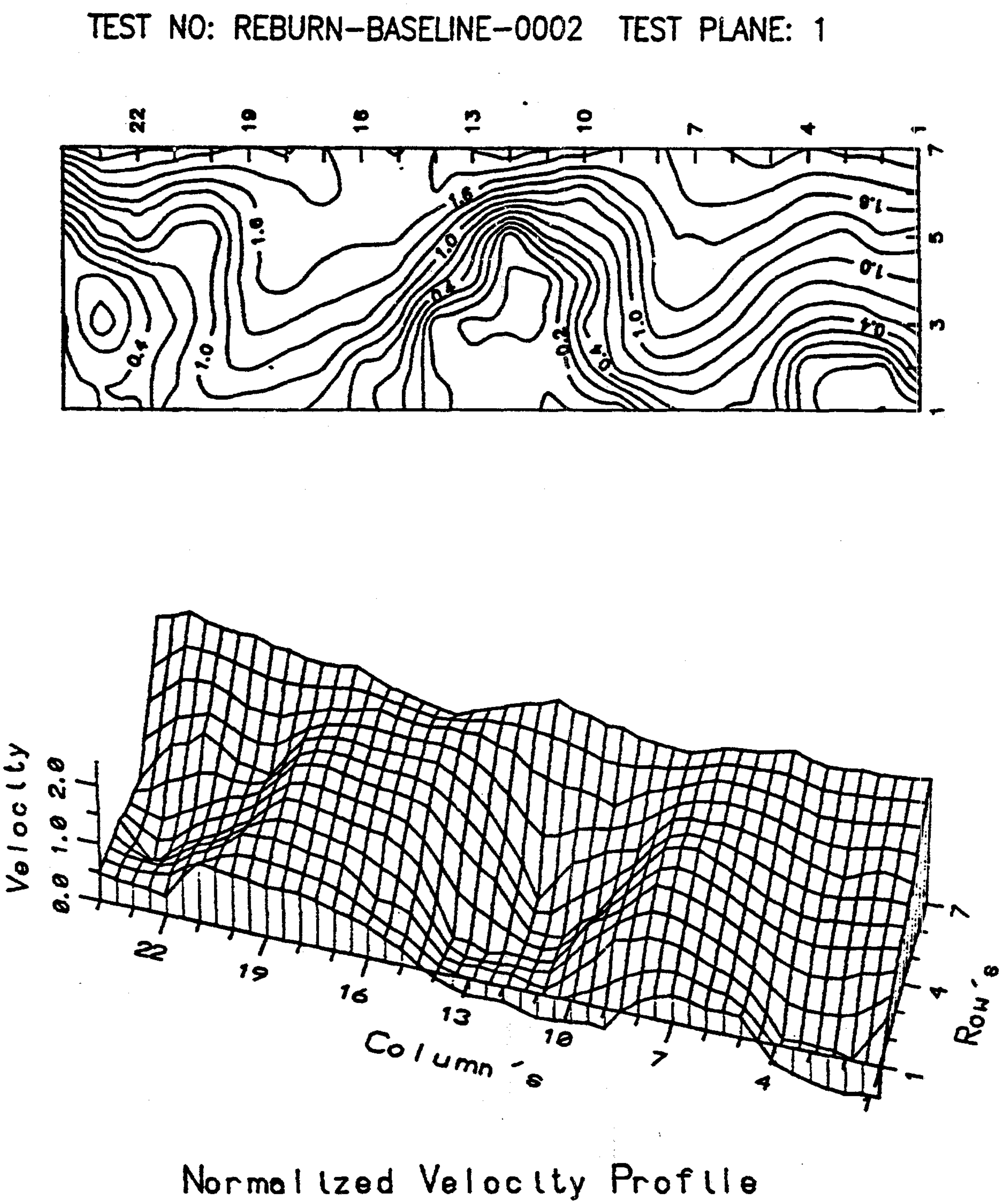
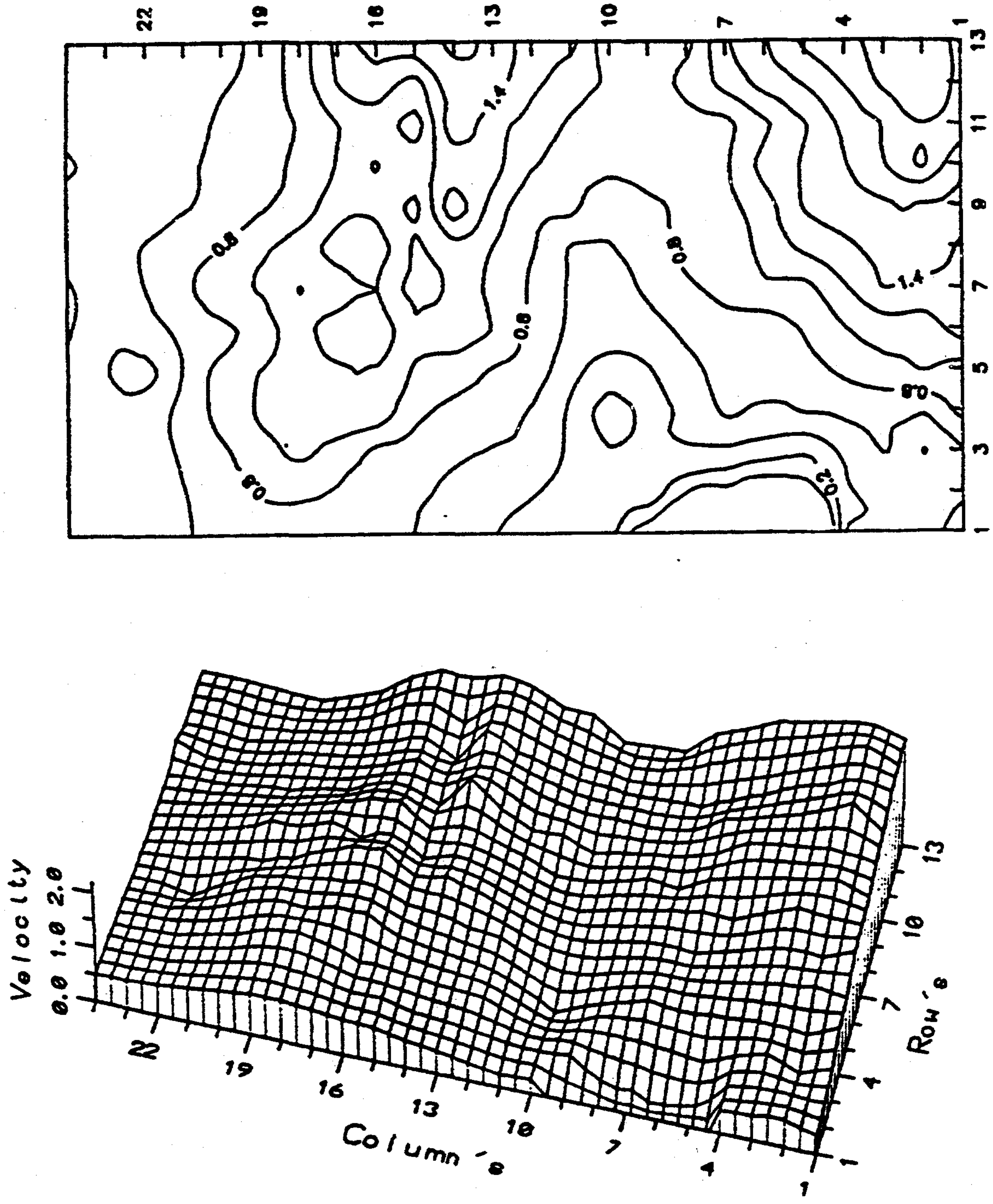


Figure 7-4
Baseline Axial Velocity Contours, Plane 1



Normalized Velocity Profile

Figure 7-5
Baseline Axial Velocity Contours, Plane 4

intermediate velocities were sized for flow rates of natural gas mixed with flue gas recirculation (FGR) flowing at a rate equal to 10% of the total flue gas flow rate. It was found that, at all velocities tested, three injectors along the rear wall were insufficient to cover the plane. Five injectors along the rear wall were found to be the best configuration. However, the two outermost injectors suffered from jet wall attachment when injecting straight into the furnace.

Yawing these injectors toward the center of the unit eliminated this problem. Injection from the side wall also provided generally good distributions, but no better than with the more economical five rear wall injector configurations.

The addition of "pant-legs" dividers to the ends of the injection nozzle tips was found to be an effective means of enhancing the dispersion of the reburn fuel jets. Pant-legs were found to significantly improve the dispersion of the jet near the rear wall.

The most effective use of yawing was obtained by providing two fuel injection levels. Each of the three inboard upper nozzles were split and yawed, using pant-legs, while the lower nozzles were not split and allowed to penetrate to near the division wall. Since it would not make sense to put pant-legs on the outermost sets of injection nozzles (being located next to the side walls), these nozzles, both upper and lower, were yawed toward the center of the furnace.

The Screening Level 2 test matrix for the reburn fuel injectors was developed from the Screening Level 1 results discussed above. Screening Level 2 mixing studies supported most of the conclusions from the initial smoke flow visualization studies and permitted the selection of an optimum reburn fuel jet configuration. The penetration and dispersion performance of the injectors was a function of the flow field into which they were injected. Injectors that were firing into the lower velocity segments along the rear wall of the furnace at a simulated velocity of 100 ft/sec were capable of penetrating all the way to the division wall, while those that injected into the higher velocity zones, associated with the two lower cyclones, could not. It was found that an injection velocity of 300 ft/sec was too high, resulting in jet impaction on the division wall almost directly across from the point of rejection. Reducing the recirculated flue gas flow rate below 10% generally resulted in reduced levels of dispersion. It was found that tilting the nozzles down improved the overall dispersion of the jet at the outlet of the reburn zone, while tilting upward reduced the dispersion. The configuration shown in Figure 7-6 was chosen as the recommended reburn fuel injector configuration.

Locations for air injectors for the burnout zone were limited to the side walls and one central location on the front wall because of interferences on the front wall of the unit. The choice of candidate burnout air injection configurations/locations was also guided by the need to inject air into a zone that was partially obstructed by cyclone burner hanger tubes. Figure 7-3 shows the locations that were evaluated for burnout air injections.

Each burnout air configuration shown on Figure 7-3 was evaluated at 150 and 300 ft/sec, three tilts (-20°F, 0°, +20°), and configuration specific yaws ranging between plus and minus 20°. During all burnout air injection tests the recommended reburn fuel injection configuration was installed and was in service.

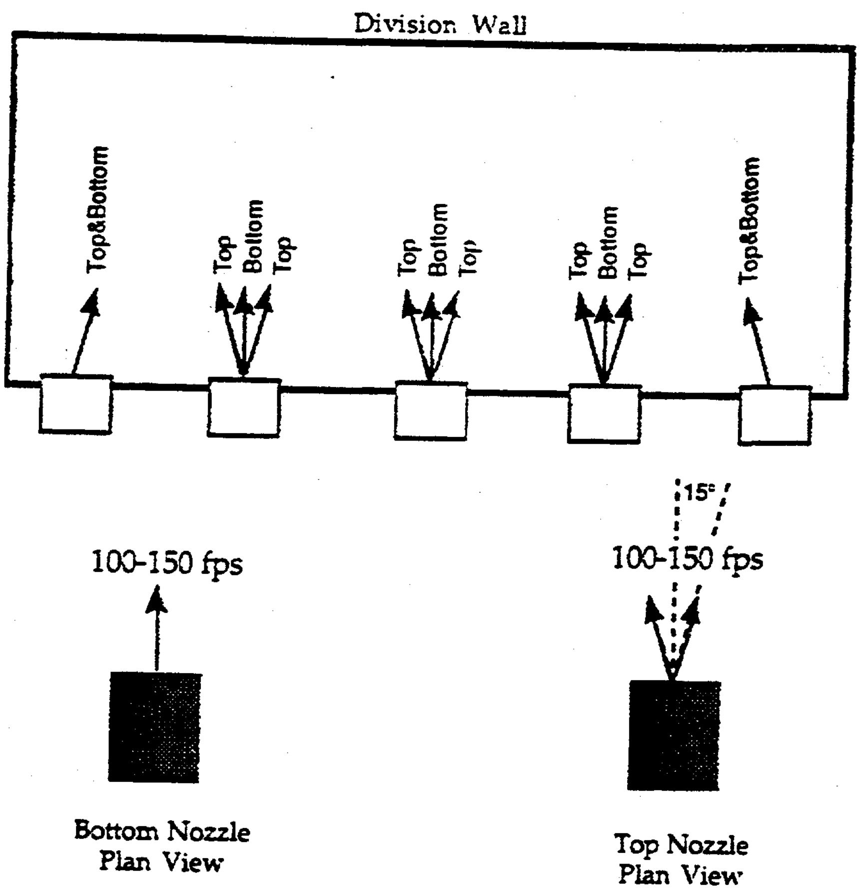


Figure 7-6
Recommended Reburn Fuel Injector Configuration

Smoke flow visualization tests of burnout air injectors showed trends consistent with the reburn fuel injection system tests; i.e., the jet penetration and dispersion increased as the burnout air jets were tilted into the flow and yawed for maximum dispersion.

The testing indicated that to effectively mix burnout air in the upper secondary furnace, a burnout air injection velocity of 225 ft/sec should be used. The recommended burnout air injector configuration is shown schematically in Figure 7-7. The configuration is represented by locations "A" and "B" on each side wall with two nozzles, one above the other, at each location. The injectors at "A" were directed straight in. Those at "B" were tilted down 10 degrees and yawed 10 degrees toward the rear of the unit. To aid in field-tuning of the system each nozzle was given a tilt and yaw capability of plus and minus 20 degrees.

Reburn System Design Requirements

The objectives of the reburn system design were:

(1) To meet performance criteria for effective NO_x reduction while minimizing any impact on boiler performance or boiler normal operation.

(2) To incorporate operational flexibility within the design to permit optimization of performance in the field.

Injection of reburn fuel into the high temperature zone enhances NO_x reduction by favoring higher chemical reaction rates; however, reburn fuel should not be injected before the bulk of the primary fuel has burned to completion. If injected too early in a coal fired boiler, natural gas, as the reburn fuel, would preferentially burn before the coal char particles have burned to completion. This could increase the possibility for unburned carbon while, additionally, not permitting all the char bound nitrogen to be released prior to the reburn zone. A stoichiometry in the range of 0.90 to 0.95 has been found to represent a reasonable balance between achieving a desirable stoichiometry from the standpoint of NO_x reduction chemistry and a stoichiometry that will not exacerbate ash deposition and/or boiler tube wastage. Though the reaction kinetics for NO_x reduction in the reburn zone are quite fast, requiring on the order of 0.1 second, the remainder of the residence time in the reburn zone is required to achieve good mixing of the reburn fuel with the bulk flue gas. The naturally occurring small amount of oxygen in the flue gas entering the reburn zone was found to be sufficient to promote the desired formation of OH and H radicals. Effective and rapid mixing of reburn fuel ensures that all NO_x entering the reburn zone will contact the intermediate nitrogen-containing species so that maximum NO_x reduction is possible. Effective mixing must be achieved in such a way that there is no direct fuel impingement on boiler walls. This impingement could exacerbate tube wastage or iron-related ash deposition by creating low local stoichiometries. Effective mixing would eliminate extremes between highly oxidizing and highly reducing atmospheres which could cause corrosion. Other practical considerations involve minimizing the number of boiler penetrations and the avoidance of unnecessarily costly boiler modifications relative to the number and placement of reburn fuel injectors. The number and placement of reburn fuel injectors must not create thermal or structural boiler problems. The reburn fuel injection system should have sufficient flexibility to permit on-line adjustment to maintain optimum mixing as a function of boiler operational variables, such as load changes, that could alter gas flow patterns within the

Test No. 412

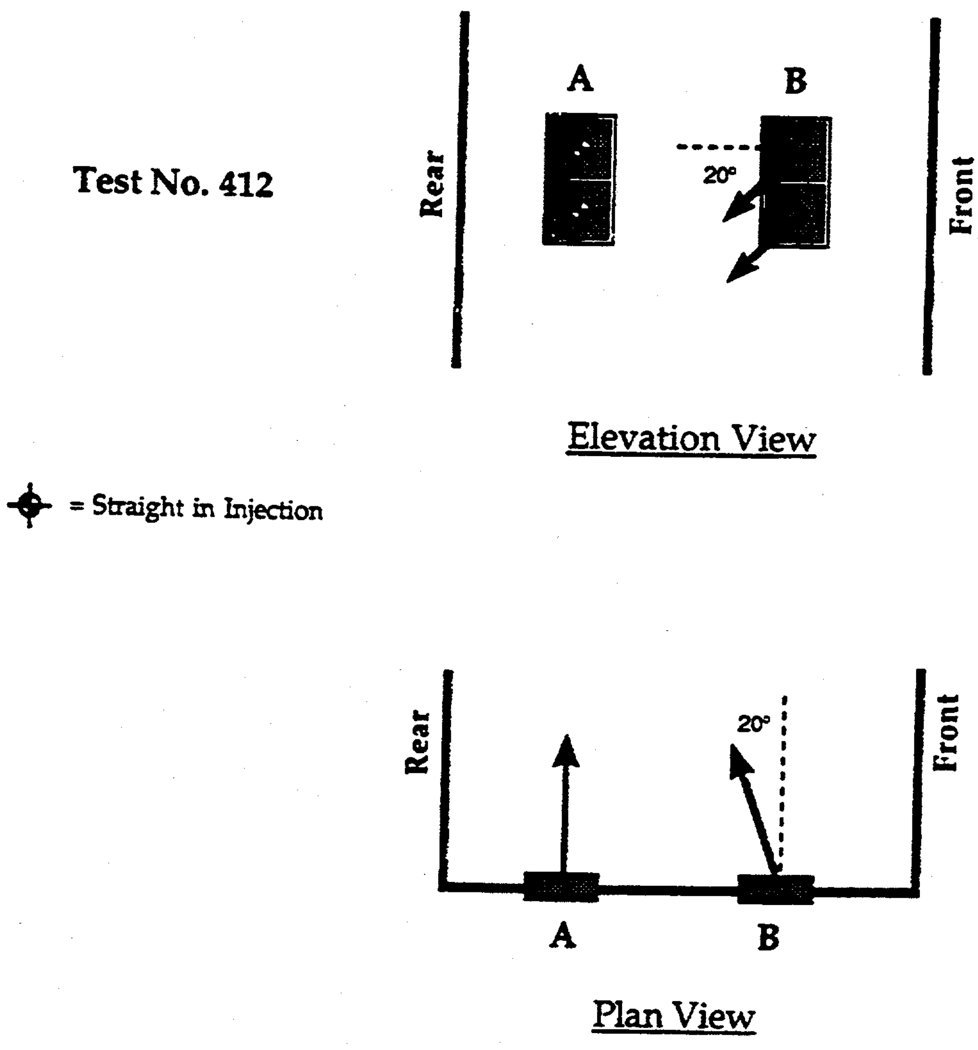


Figure 7-7
Recommended Burnout Air Injection Configuration

reburn zone. Since the amount of reburn fuel required will likely change as a function of boiler load, a control system should be provided which will provide automatic load following capability. The reburn fuel control system should also have permissives which must be satisfied to ensure safe operation.

The key design criteria for the reburn zone are summarized as follows:

- Inject reburn fuel into as high a temperature zone as possible, commensurate with releasing all fuel-bound nitrogen upstream of the reburn zone
- Maintain average stoichiometry between 0.90 and 0.95
- Permit a small amount of O_2 to promote formation of OH and H radicals
- Maintain a residence time between 0.5 and 0.7 seconds
- Maximize entrainment, mixing, and dispersion of reburn fuel
- Avoid direct fuel impingement on boiler walls
- Minimize the number of required boiler penetrations
- Locate fuel injection nozzles to minimize boiler/structural steel modifications
- Provide for maximum flexibility of reburn fuel jet direction and flow rates
- Provide a fuel flow rate control system with automatic load following capability
- Provide safeguards for fail-safe operation

For the burnout zone, unlike the reburn zone, air should be injected in as low a temperature gas as possible to prevent the reformation of NO_x. However, lower temperatures could prevent complete burnout of combustibles leaving the reburn zone, so a balance must be struck between the dual objectives of minimizing NO_x reformation and complete combustible burnout. Rapid and thorough mixing in the burnout zone is necessary. Although the reaction between fuel and oxygen is quite rapid, the remainder of the recommended 0.6 - 0.8 second residence time is needed to achieve effective mixing rather than for combustion reaction time per se. Direct impingement of air on furnace walls should be avoided, more for reasons of preventing local temperature increases than for any concern about the presence of an oxidizing atmosphere. The amount of air should be just sufficient to achieve desired fuel burnout; an overabundance of excess air contributes to dry gas losses and the potential for NO_x reformation in the burnout zone.

Key design criteria for the burnout zone were:

- Inject burnout air in as low a temperature zone as possible, commensurate with obtaining fuel burnout before entering the first convective surface.
- Provide for rapid mixing of air to minimize pockets of unburned fuel.
- Avoid direct air impingement on furnace walls.
- Minimize final excess oxygen, commensurate with obtaining good fuel burnout.
- Provide for a residence time in the range of 0.6 to 0.8 second.
- Minimize the number of required boiler penetrations, commensurate with obtaining good mixing.
- Locate burnout air injectors to minimize boiler structural modifications while providing good mixing.
- Provide for maximum flexibility of air jet direction and flow.
- Provide an air flow rate control system with automatic load following capability.
- Provide safeguards for fail-safe operation.

Reburn System Components and Installation

Five separate windboxes were installed at the rear wall of the unit for the reburn fuel nozzles. Modified waterwall panels were installed at these locations for installation of the reburn fuel nozzles. To supply recirculated furnace gas used as carrier for the natural gas in the original system, ductwork from the gas recirculation fan and a windbox header were also installed. The reburn fuel equipment was located at Elevation 882'. From inside the furnace, facing the rear wall, the windboxes were designated 1A through 1E from left to right. The three center windboxes (1B, 1C, 1D) face directly into the furnace and are square to the rear wall. The centerline of the left and right windboxes (1A and 1E) are yawed 20 degrees away from the respective side wall (toward the center of the furnace) to avoid jet wall attachment. Each windbox was divided into three horizontal compartments. The upper and lower compartments were 10" high and the middle ones were 8" high. All of the compartments were 16" wide. The reburn injector installation is shown in Figure 7-8.

Four separate windboxes (two on each side) were installed at the side walls of the unit for the burnout air nozzles. Modified waterwall panels were installed at these four locations. To supply hot combustion air for the windboxes, connecting ductwork from the secondary air ducts was installed. The burnout air equipment consisted of four tilting windbox assemblies located in the left and right side walls of the furnace at elevation 905' 8". There were two windboxes in each side wall. The nozzle tip arrangement was the same in all four windboxes. Each windbox was divided into two horizontal compartments. The upper compartments were 11 1/2" high and the lower ones were 10" high. All compartments were 18" wide.

Boiler Thermal Performance

Since operation of the reburn system required reduction of the main fuel by up to 20% and an equivalent injection of reburn fuel into the lower portion of the secondary furnace, changes in the boiler gas and steam side thermal performance were expected. A series of proprietary ABB/C-E mathematical models, in conjunction with baseline data, furnace dimensions, and operating data supplied by Ohio Edison, were used to verify that satisfactory thermal performance of the unit would be achieved when operating the reburn system and that no adverse effects on the boiler would occur. The calculations for boiler performance with reburn were for the original reburn system design in which the natural gas was injected in a mixture which included recirculated flue gas flowing at a rate equal to 10% of the exit gas flow rate. Specific items investigated in the performance study were the following:

- Furnace heat absorption profile
- Convection pass performance
- Boiler efficiency
- Boiler circulation; departure from nucleate boiling.

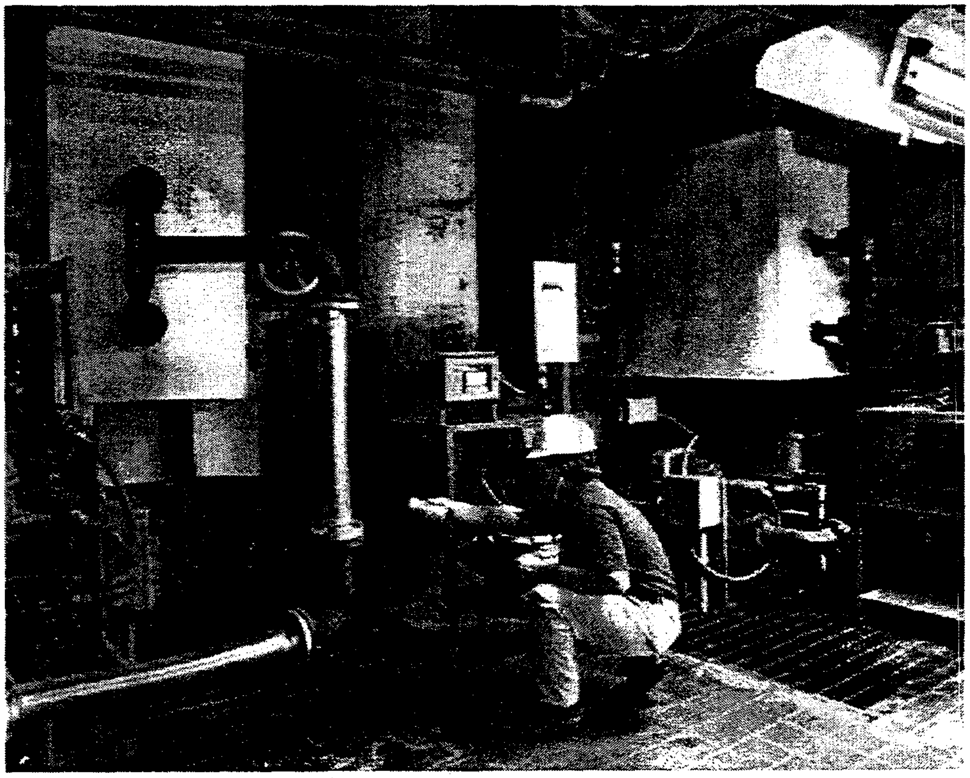


Figure 7-8
Reburn Fuel Injection Windboxes

The general approach used to evaluate boiler thermal performance was:

- Calculate or obtain physical data for the boiler components (e.g., heating surfaces, tube diameters, tube arrangement, tube material, free gas areas).
- Set up computer programs to calculate boiler efficiency, cyclone/furnace performance, convection pass performance, and air heater performance.
- Calibrate programs with baseline data. Determine required calibration factors to match baseline data.
- Calculate baseline boiler performance.
- Calculate boiler performance with reburn.
- Compare boiler performance with reburn to baseline performance.

Baseline Boiler Performance

The first step in calculating the impact of the reburn system on boiler performance was to establish the baseline performance for reference purposes. Baseline boiler performance was calculated using the heat loss method. The calculated losses and resultant efficiency are shown in Table 7-1. Knowing the boiler efficiency and the output of the unit, the energy input of the coal was calculated. Based on the coal analysis shown in Table 7-2, combustion calculations were performed to establish the gas and air weights. That data provided the necessary inputs for the convective pass program. The convection pass program was run backwards to determine: (1) furnace exit gas temperature, (2) surface effectiveness factors, and (3) intermediate steam and gas temperatures.

Furnace/cyclone performance calculations were performed next using C-E's lower furnace program. Program inputs were varied until conditions were met relative to cyclone combustion efficiency, gas temperatures measured in the unit, and the furnace outlet temperature back-calculated by the convection pass program.

A heat absorption baseline profile was then generated using C-E's lower furnace program. This is shown by the solid line in Figure 7-9. Conditions for this calculation were 108 MW and 12% excess air. The heat absorption rates shown are perimeter average rates. Where heat transfer surfaces are more or less uniformly covered with refractory or ash deposits, the local rates should be reasonably close to the average rates. Where tube sections are not covered with refractory or ash deposits, local rates could be much higher than the average rates. The calculated average rate for the cyclone is approximately 83,000 Btu/hr-ft^2, and for the primary furnace and screen tubes the rates are approximately 54,000 and 44,000 Btu/hr-ft^2, respectively.

The total lower furnace heat absorption can be calculated by multiplying the heat absorption rates from the profile by the EPRS (Effective Projected Radiant Surface) and by correcting for casing heat loss. If the heat absorbed by the evaporative surface in the convection pass is added in, the sum should equal the heat absorbed by the fluid from the boiler inlet to the steam drum outlet; this was checked and was found to be in agreement within 2%.

Table 7-1
Calculated Boiler Efficiency - 108 MW

	Baseline Coal	Reburn 80% Coal/20% N.G.
Dry Gas Loss	2.84	2.63
Moisture from Fuel Loss	4.47	5.32
Moisture from Air Loss	0.07	0.06
Radiation Loss	0.24	0.25
Ash Pit Loss	0.74	0.62
Miscellaneous	0.50	0.50
Total Losses	8.86	9.38
Boiler Efficiency	91.14	90.62
Stack Temp °F	267	269

Table 7-2
Coal Analyses - % by Weight

Ultimate		Proximate	
Moisture	7.45	Moisture	7.45
Hydrogen	4.48	Volatile Matter	35.05
Carbon	63.00	Fixed Carbon	44.14
Sulfur	3.26	Ash	13.36
Nitrogen	1.12		
Oxygen	7.33	Total	100.00
Ash	13.36		
Total	100.00	HHV (Btu/lb)	11559

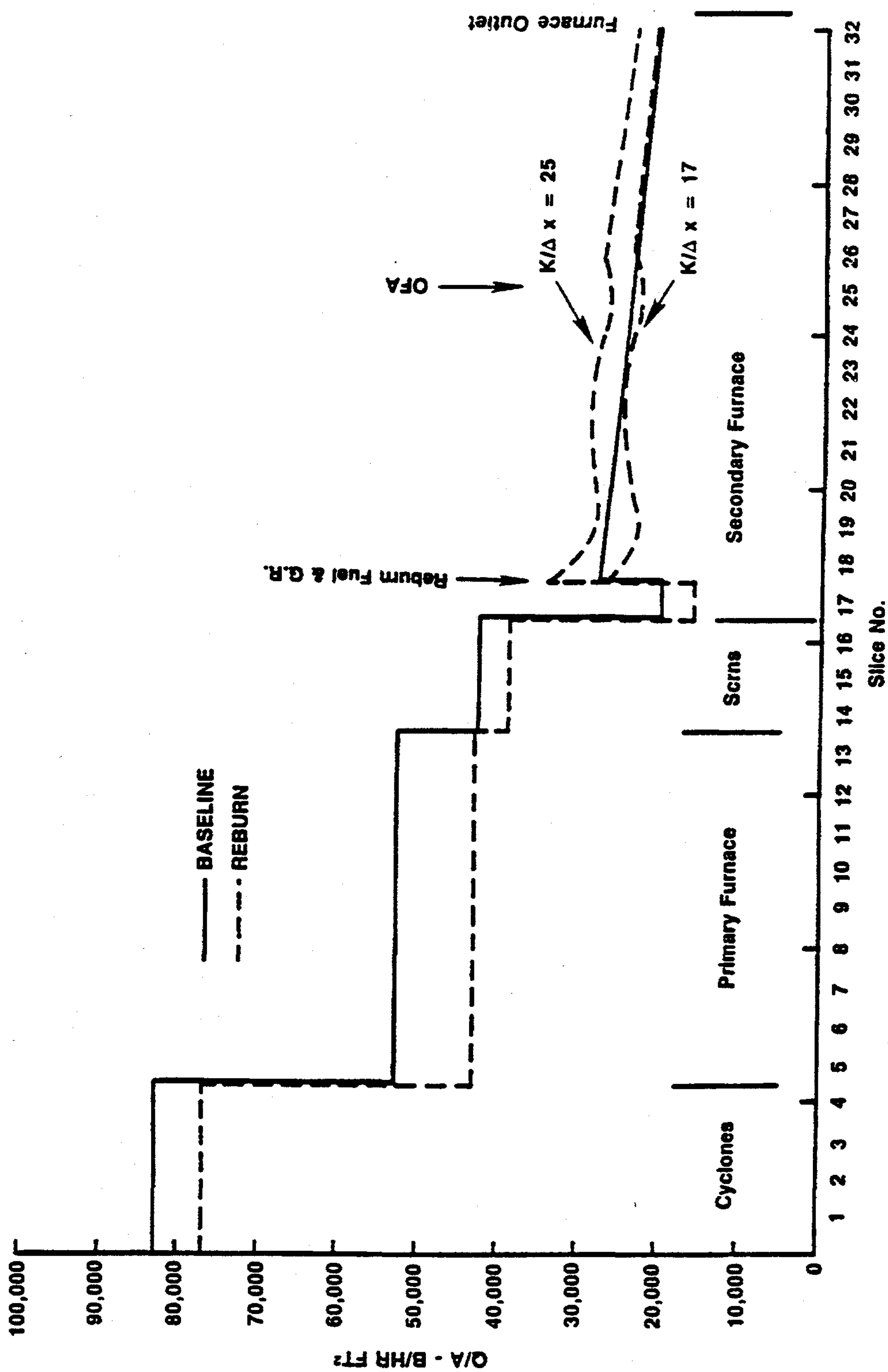


Figure 7-9
Furnace Heat Absorption Rate-108 MW

Boiler Performance with Natural Gas Reburn and Recirculated Flue Gas

Boiler performance with gas reburn was calculated in the normal forward design mode; i.e., the programs were run in the following order: (1) cyclone/lower furnace, (2) convection pass, (3) air heater, and (4) boiler efficiency. Process flow quantities were determined from assumptions regarding reburn natural gas flow rates, recirculated flue gas flow rates, burnout air flow rates, and the locations of the reburn fuel and burnout air injectors.

For predicting performance with reburn, the lower furnace program was run with the firing rate in the cyclones reduced by 20%. Excess air was maintained at the same level as that of the base case, 12%. Boundary surface conditions (waterwall deposits) were varied in the secondary furnace: (1) in one case they were kept at the same condition as the back-calculated value for the base case, and (2) in the other case it was assumed that there would be about 30% less thermal resistance because of the decreased amount of coal being fired, the expected lower gas temperatures, and changes in ash deposit characteristics.

The calculated heat absorption profile for the reburn case is shown with a dotted line in Figure 7-9. The profile indicates a 10% reduction in overall waterwall heat absorption with reburn for the assumed case where the thermal resistance of ash deposits remained the same as for the base case. For the assumed case where the thermal resistance dropped by 30% in the secondary furnace, the overall waterwall heat absorption would be about 5% less with reburn than for the base case.

Utilizing the output from the lower furnace program, the convection pass program was then run to calculate superheater and reheater performance. The effective heating surfaces calculated from the base line data was input to the program. A weighted fuel analysis (80% coal + 20% natural gas) was used to calculate changes in gas properties. In the initial boiler performance calculations which included recirculated flue gas and a resulting increased gas flow rate, more heat was picked up in the convection pass with reburn than for the base case. Slightly more heat is also picked up by the air heater with reburn.

One consequence of picking up more heat in the convection pass was that increased superheater spray water flow was required. However, the calculated increase in superheater spray was within the capability of the unit even under a worst case scenario. As shown earlier in Table 7-1 the calculated boiler efficiency with natural gas reburn was about 0.5% less than the base case primarily due to greater moisture from fuel losses; i.e., the higher hydrogen content of the natural gas resulting in more water vapor being formed than when firing coal.

Two other boiler thermal performance related questions were addressed, namely the effect of reburn on boiler circulation and the effect of reburn on departure from nucleate boiling (DNB). DNB is defined as the occurrence of film boiling under which the tube inside (water side) heat transfer coefficient drastically deteriorates and tube overheating/failure can occur.

A computer program was used to perform boiler circulation calculations. The program balances the pressure drops of the multiple parallel circuits based on available thermal heads between the downcomers and risers. Both baseline and reburn cases were investigated. The results of this study showed that tube offsetting, for purposes of making openings for fuel and air injectors, would have an insignificant effect on circuit flow and exit circulation ratio.

Relative to the question of DNB, the division wall between the primary and secondary furnaces was evaluated since this surface has the higher heat transfer duty. The criterion for evaluation of DNB was specification of the maximum allowable steam quality, which depends on pressure, heat flux, and mass flow of water/steam. To avoid DNB the actual circuit steam quality must be kept less than the maximum allowable steam quality with adequate safety margin. Calculations determined that 56% steam quality (or less) ensures a DNB free condition. The actual steam quality in the highest duty location, the division wall, is calculated to be well under 10% with reburn. The occurrence of DNB was therefore not seen as a problem.

Control System

The reburn control system used an Allen Bradley programmable controller to operate the reburn system in an automatic, load-following mode. Natural gas flow, at a predetermined percentage of unit heat input, and recirculated flue gas flow were based on coal flow demand input. The burnout air flow was based on natural gas flow with the final excess oxygen designed to be slightly lower than the normal cyclone excess oxygen level.

The reburn system was tied into the main boiler control system for safety and control purposes. The natural gas reburn fuel controls were set up in a last-in-service/first-out-of-service logic. The FGR system remained in service independent of the reburn natural gas, except for loss of control power. All system dampers/valves fail shut except for the natural gas vent valves which fail open.

8

TEST PLANNING / MEASUREMENTS

Data for reburn system performance and boiler performance was measured during parametric tests, maxi tests, and long-term load dispatch testing. Long-term corrosion monitoring was conducted concurrently with the reburn system performance tests. Although the focus of the project was NO_x reduction, it was important to also measure boiler performance and component life to assure that these requirements were not compromised. The scope of the tests is described in the following subsections. Also described are the emissions and boiler performance measurement equipment, the method used for data analysis, and the quality assurance/quality control procedures.

Program Scope

Parametric Testing

A comprehensive set of parametric tests was performed on the unit under baseline and reburn operation for the original reburn system during October 1990 through June 1991. Another set of parametric tests was performed during October and in late 1991 on the modified reburn system. The objective of these tests was to characterize the reburn system and document the effects of varying operating parameters and equipment settings on NO_x and CO emissions as well as boiler performance and the steam temperatures. To expedite data collection, several parametric tests were performed on a test day, and data collection was limited to flue gas composition and boiler operating data. For selected tests, carbon in ash was also measured.

Maxi Testing

During the parametric testing of the original reburn system, four comprehensive tests (referred to as "maxi" tests) were conducted. Maxi tests were run at generator loads of 108 and 86 net megawatts for both baseline (100% coal firing) and 18% natural gas reburn conditions. An additional maxi test at full load was conducted at reburn conditions for the modified reburn system. The reburn configuration found to represent an optimum during the parametric investigations was utilized during the maxi reburn tests.

The purposes of the maxi tests were to:

- provide full sets of test data for boiler performance calculations.

- assess the effect of reburning on the flue gas conditions entering the electrostatic precipitator (ESP).

- measure the size distribution and mass loading of particulates entering the ESP.

- evaluate the effect of reburn on the collection efficiency of the ESP.

Long-Term Dispatch Testing

Long-Term Dispatch Testing was conducted between March 2, 1992 and June 19, 1992 after optimum boiler and reburn system parameters for long-term testing had been identified. Gaseous emissions data and boiler operating data were logged on a continuous basis at five-minute intervals. Data logging was halted only for periods of equipment servicing, inspection, and QA/QC procedures, and during periods when the reburn system or the boiler were off-line.

Corrosion Monitoring

Corrosion monitoring was performed to evaluate the effect of reburn operation on tube life, if any. Corrosion measurement methods and monitoring results are described in Section 14, "Boiler Tube Thickness Monitoring Program."

Flue Gas Sampling and Analysis

Sampling During Parametric Tests and Maxi Tests

Flue gas sampling and analysis were performed in general accordance with the EPA Methods. Flue gas was sampled point-by-point using a ten-point sampling matrix located at the air heater inlet as shown in Figure 8-1. Flue gas was extracted using stainless-steel probes which had sintered metal filters. Impact shields were installed at the probe inlets to keep them from plugging. The flue gas then passed through a second particulate filter and then to a solenoid valve box. Individual probes were selected by switching on the solenoid valve for that particular probe. The sample was drawn down to an instrument and gas analysis trailer at a flow rate of 20 - 25 cfm. This high rate of sample delivery minimized the residence time of wet, dirty flue gas in the sampling system so that the removal and/or destruction of NO_x in the sampling system was minimized. The gas analysis train is shown in Figure 8-2. The sample was chilled to dry the flue gas. Part of the sample was re-filtered and fed to the instruments to be analyzed for NO_x, O_2, CO, CO_2 and SO_2; the remainder was discharged. Specifications of the instruments are given in Table 8-1. Initially, a separate sample was drawn from the ESP breeching and analyzed for THC (total hydrocarbons) but as its concentration was found to be negligible, THC analysis was discontinued.

Sampling During Long-Term Dispatch Tests

Flue gas was extracted at the precipitator inlet breeching using an averaging probe made up of three individual sampling probes of different lengths that were manifolded together. Probe sampling lengths were chosen according to the equal area procedure described in EPA Method 1. The probes were constructed in a similar manner as those used at the air heater inlet. After leaving the averaging probe, the sample was filtered and drawn down to the instrument trailer.

Sample tubing exposed to the environment was insulated and heat-traced to keep the moisture in the flue gas from freezing and blocking the sampling line. The flue gas sample was conditioned and analyzed in a manner similar to that of the parametric testing sample.

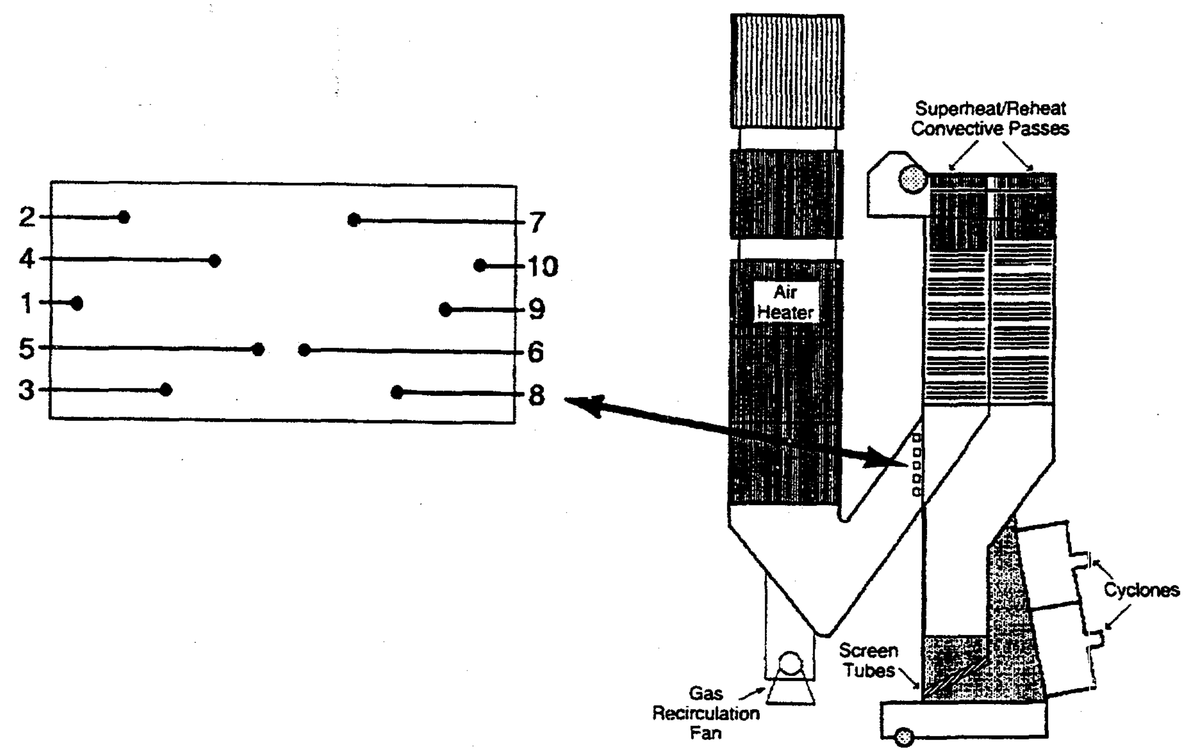


Figure 8-1
Boiler Exit Gaseous Emissions Sample Matrix

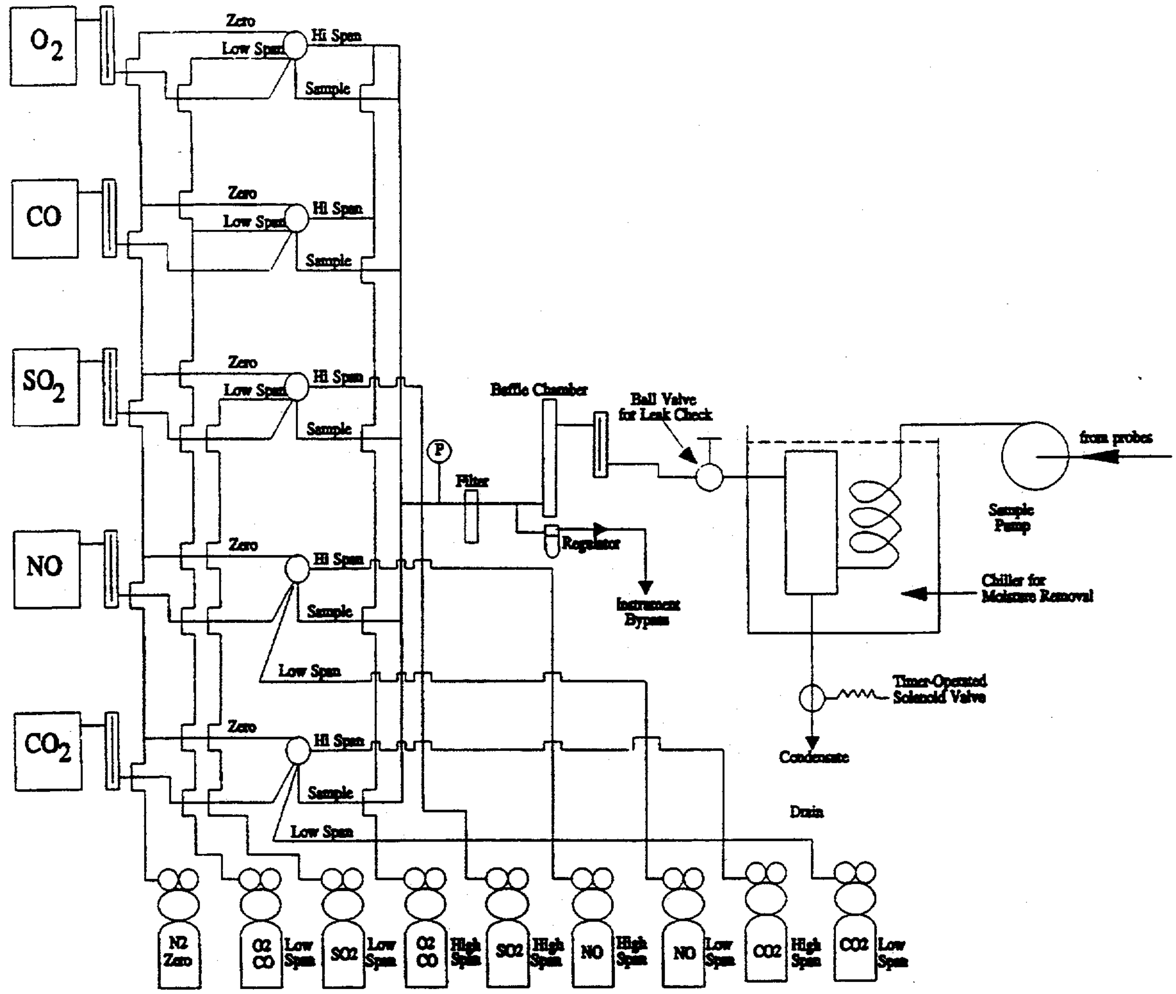


Figure 8-2
Schematic of Flue Gas Sampling and Analysis System

Table 8-1
Specifications of Gas Analysis Instruments

Gas Specie	Made by:	Principle	Range	EPA Reference Method
NO	TECO	chemiluminescence of NO oxidized to NO_2 by ozone	0 - 1000 ppm	7E
O_2	Thermox	fuel cell - difference in potential between flue gas and ambient air	0 - 25%	3A
CO	Horiba	non-dispersive infrared	0 - 1000 ppm	10
CO_2	Horiba	non-dispersive infrared	0 - 20%	3A
SO_2	Western Research	UV absorption	0 - 4000 ppm	6C
THC	Beckman	flame ionization		25A

Boiler Performance and Operations Data

A set of 62 boiler and reburn system operation parameters was logged on an IBM-PC compatible computer directly from the plant's Bailey System 90 control system. During parametric and maxi tests, additional data were recorded from control room instrumentation. The logged data included:

- individual cyclone air and coal flows
- total gas flow
- primary and secondary cyclone air flow and the reburn system burnout air flow
- superheat and reheat steam temperatures and pressures
- unit load
- superheat and reheat attemperator spray flow.

A complete list of parameters logged is included in Appendix A.

Coal Composition

Coal samples were collected twice weekly as part of Ohio Edison's fuel specification check. These samples were sent to ABB-CE for proximate and ultimate analyses. Coal samples were also taken during the maxi tests from each of the active feeders. Coal analyses are listed in Appendix D.

ESP Performance Data

Fly Ash Loadings

To compute ESP inlet loading and ESP efficiency, fly ash samples were collected at the ESP inlet breeching and at the stack. Both samples were collected in general accordance with EPA Method 5, in which the flue gas sample is extracted isokinetically and the particulate matter is collected on a filter placed in a box heated to 250° F.

Fly Ash Particle Size Distribution

Particle size distribution samples were collected from the stack using an Andersen Mark III cascade impactor, with an Andersen pre-separator with a cut size of 10 microns used upstream of the impactor.

Fly Ash Resistivity

In-situ fly ash resistivity was measured at the ESP inlet using a Wahlco resistivity probe. SO_3 concentration in the flue gas was computed by measuring the acid dew point using a probe manufactured by Land Corporation.

Carbon in Ash

Fly ash samples were taken at the ESP inlet using a high volume sampler. Boiler bottom ash was sampled from the slag tanks below the wet bottom slag taps. Both of these samples were analyzed for carbon in ash to document unburnt fuel losses.

Flue Gas Temperature and Flow Field

Gas temperatures and velocities were measured periodically at three locations on the rear wall at an elevation 2 ft. 6 in. below the reburn fuel injection elevation. Velocities were measured using a five-hole pitot probe to obtain all three components of velocity. Gas temperature was also measured at the reburn zone outlet immediately below the superheater.

Reburn Zone Inlet Conditions

To better understand the chemical and physical processes that take place in the reburn zone, a series of measurements were made upstream and downstream of the reburn zone. Measurements within the reburn zone could not be made because of physical access difficulties.

Cyclone Exit O_2

Flue gas was extracted from the cyclone exit, actually downstream of the screen tubes and immediately upstream of the reburn fuel injection location, using four water-cooled probes mounted along the furnace rear wall. Each probe was connected to the plant's O_2 instrument, and its output was transmitted to the control system. During parametric and maxi testing, the O_2 levels were also measured directly from the probes using a portable Teledyne electrochemical cell O_2 meter.

Cyclone Exit O_2 for Long-Term Testing

Because the cyclone exit O_2 probes were located in a very high temperature area, they plugged frequently. Once the probes plugged, the reported cyclone exit O_2 was unreliable because of high air in-leakage into the O_2 instrument. This made the plant-reported cyclone exit O_2 value logged off the plant's control system unsuitable for use in data analysis. A calculated value based on the plant-reported cyclone air and fuel flows was used for cyclone exit O_2 during long-term testing. The equation is as follows:

$$\text{Cyclone exit } O_2 \text{ (mole \%, dry)} = 20.9 \times \left(1 - 11.52 \times \frac{M_{coal}}{M_{air}}\right)$$

where: M_{coal} = mass flow rate of coal
M_{air} = mass flow rate of air to the cyclones

The constant in the equation, 11.52, was determined from measurements of coal, air, and cyclone exit O_2 measured when the cyclone exit probes were not plugged.

Data Analysis

Reburn Zone Stoichiometry

One of the key variables affecting NO_x emissions is reburn zone stoichiometry (RZS) defined as the stoichiometry of the flue gas after the reburn fuel is injected but before the burn out air is added to the flue gas. The equation relating RZS to cyclone exit O_2 and measured gas and coal feed rates, derived in the following paragraphs, depends on the chemical properties of coal and gas and stoichiometric ratios for coal and gas.

RZS is related to mass flow rates of coal, air and gas, and stoichiometric ratios for coal and gas as follows:

$$RZS = \frac{M_{air}}{Z_{coal} \times M_{coal} + Z_{gas} \times M_{gas}}$$

where:
M_{air} = mass flow rate of air
M_{coal} = mass flow rate of coal
M_{gas} = mass flow rate of natural gas
Z_{coal} = air/coal mass flow ratio for complete combustion of coal
Z_{gas} = air/coal mass flow ratio for complete combustion of natural gas

Dividing the numerator and denominator in the above equation by the mass of air required for stoichiometric coal combustion ($Z_{coal} \times M_{coal}$), expressing the mass flows of coal and natural gas in terms of their heat inputs, and simplifying yields:

$$RZS = \frac{CZS}{1 + \frac{Z_{gas}}{Z_{coal}} \times \frac{R}{\frac{HHV_{gas}}{HHV_{coal}} \times (1-R)}}$$

where:
CZS = Cyclone zone exit stoichiometry
R = natural gas energy input/(natural gas energy input + coal energy input)
HHV_{gas} = high heating value of natural gas
HHV_{coal} = high heating value of coal

The cyclone zone exit stoichiometry is related to the cyclone exit O_2 and additional stoichiometric parameters as follows:

$$CZS = 1 + \frac{\gamma \times M_{dfg}}{M_s \times (1-\gamma)}$$

where:
γ = normalized cyclone exit O_2 = cyclone exit O_2 (mole %, dry) /20.9
M_{dfg} = moles of dry flue gas product per pound of coal combusted
M_s = moles of air required per pound of coal for stoichiometric combustion

Values of some of the relevant ratios, based on average fuel compositions are as follows:

$$\frac{M_{dfg}}{M_s} \approx 0.97$$

$$\frac{HHV_{gas}}{HHV_{coal}} \approx 1.9 \text{ to } 2.1$$

$$\frac{Z_{gas}}{Z_{coal}} \approx 2.0$$

Approximating $M_{dfg}/M_s = 1.0$ and $HHV_{gas}/HHV_{coal} = 2.0$, the equation for RZS simplifies to:

$$RZS = \frac{20.9}{20.9 - \text{Cyclone exit } O_2 \text{ (mole \%, dry)}} \times (1 - R)$$

This equation has been used for all gas analysis data reduction. The approximations introduce less than a 1% error in the calculated value of RZS.

Boiler Performance Analysis

Boiler performance was calculated using data recorded by the plant's data logger, from manually - collected data displayed in the control room, and from laboratory chemical analyses. Boiler thermal output was calculated from the enthalpy rise and flow of steam and water passing through the unit. Heat transfer rates were calculated from the measured heat absorptions, heat transfer areas, and the log mean temperature differences. Boiler air and gas flows and boiler efficiency were calculated by ABB proprietary methods similar to the ASME PTC 4.1 heat-loss method. This method is discussed in further detail by Singer (1991), pages 22-24 through 22-29.

QA/QC Procedures for Gaseous Measurements

QA/QC Procedures during Parametric and Maxi Testing

All gaseous instruments were housed in a temperature-controlled trailer to minimize drift. Calibration gases used for all instruments were EPA Protocol 2, NIST traceable. The flue gas sampling and analysis system was made of stainless steel, Teflon or glass as specified by EPA Methods, or plastic tubing that was known to be non-reactive with flue gas. Further, by drawing the sample down at rates of 20 - 25 cfm., the residence time of the flue gas in the sample system was minimized.

During the parametric and maxi tests, instrument calibration (<2% of span), drift (<3% of span) and linearity (<2% of span) was checked before and after each test to make sure that they were within specifications. Sampling system bias (<5% of instrument span) was checked as necessary.

QA/QC Procedures during Long-Term Testing

During long-term testing, gaseous emissions data was collected in accordance with EPA Level 2 QA requirements. Four audits were conducted by the Research Triangle Institute, EPA's QA/QC contractor, at various times during the program. To ensure data integrity, the entire data collection system and continuous emissions monitoring (CEM) gas sampling system was thoroughly inspected by qualified personnel twice weekly. Details of this check and the standards used are described in the following subsections.

Instrument Drift

The instrument drift of the flue gas analyzers was checked to ensure that it was within allowable limits (3% of span). If the drift was greater than 1.5% of span the instrument was re-calibrated. Since measured drifts were always well within the allowable limits, it was believed that inspections performed twice weekly were adequate to ensure that test equipment was within specification.

Gas Sampling System Bias

The integrity of the gas sampling system was checked for system bias. Calibration gases were introduced at the averaging sampling probe manifold exit and the instrument response from this sample was compared to the response by directly injecting the calibration gases into the instruments. The sampling system bias was well within the 5% allowed.

Sampling Location Bias

Parametric test results were based on an arithmetic mean of emission measurements sampled at a ten-point grid located upstream of the air heater. Long-term results were based on emission measurements made from a three-point composite sample drawn from the ESP inlet breeching. To ensure that there were no significant biases between these two sets of emission data, flue gas composition was simultaneously measured and compared at these two sampling locations under identical steady-state boiler operation. This check was made several times during the long-term testing. The NO emissions were within 5% of each other.

Comparison of NO and NO_x Emissions

During the initial stages of the test program, the fraction of the total NO_x that was in the form of NO_2 was documented by measuring the difference between the NO and NO_x emissions from the boiler. The NO_2 fraction was found to be less than 5% of the total NO_x. Therefore, in accordance with EPA Method 7E, para. 5.1.2, only NO emissions were measured for the remainder of the test program. In this report, the terms NO and NO_x have been used synonymously to refer to NO emissions from the boiler.

QA/QC for Boiler Operation Data

Boiler operation data was checked in a variety of ways. During parametric and maxi tests, boiler operating data was simultaneously recorded manually from the instrumentation in the control room to compare with the logged data. During long-term testing, coal mass flow based on feeder instrumentation output was checked against bunker loading over a two-week period to calculate a correction factor for the coal flow. Further, to check that the feeder calibration had not excessively drifted during the test period, the average net plant heat rate was calculated for each hour of operation. A sudden change in the plant heat rate would have indicated a change in feeder calibration.

QA/QC Procedures for ESP Performance Measurements

Sampling procedures, selection of sampling location, sampling equipment, and calibrations were performed according to the relevant EPA Methods. Reagents used for sample recovery were reagent-grade.

9

REBURN SYSTEM INSTALLATION AND STARTUP

Installation

The reburn system was installed with minimal disruption to normal power plant operation. The four key phases of reburn system installation were: (1) procurement of material and delivery to the site, (2) pre-outage activities, (3) outage activities, and (4) post-outage activities. A key consideration was the installation of all direct boiler-related equipment/materials during the utility's normal four week boiler outage.

Major items obtained during the procurement period included the reburn fuel and burnout air windboxes, their waterwall tube panel inserts, FGR fan, recirculated flue gas and burnout air ductwork, and the control system. The FGR fan and the control system were the items requiring the longest lead time, about 26 weeks.

Pre-outage work included removal of the old FGR fan and associated ductwork along with asbestos abatement. The natural gas pipeline was installed up to the point where it connected to the windboxes. Structural steel was reinforced in those areas where the recirculated flue gas ductwork was installed and minor revamping of access stairs and platforms was performed to accommodate installation of the new ductwork.

At the commencement of the boiler outage on May 21, 1990, boiler casing and refractory at the locations for the reburn fuel and burnout air windboxes were removed exposing the straight sections of waterwall tubes to be cut out. Waterwall sections removed to accommodate the prefabricated reburn fuel and burnout air tube panels were about 3 feet by 15 feet. After welding in the tube panels, the windboxes were welded to flanges provided as part of the tube panel structure, and seal boxes were built around each windbox and tube panel to prevent any furnace leakage. Windboxes were tied into the previously installed ductwork by the installation of expansion joints which allowed for growth of the boiler versus the stationary ductwork. The boiler was hydrostatically tested, followed by the installation of refractory in the seal boxes and seal welding of all outer casing. Following an air pressure test to locate and seal weld any remaining furnace casing leaks, the boiler was fired up (to allow for chemical cleaning and curing the refractory) and returned to service on June 25, 1990.

Startup

A key activity during the post-outage timeframe was checkout and start-up of the reburn system, the objective being to verify that all components worked as designed. During the outage all mechanical and electrical subsystems were verified to be operational. During system start-up, the various subsystem interactions and sequencing were verified. Minor changes to the control system programming and adjusting of the time delays based on actual device responses were also completed. The gas reburn system was designed to operate in either a reburn mode (natural gas being injected) or a non-reburn mode (no natural gas being injected). In the non-reburn mode some minimal amount of cooling FGR or air was needed to maintain the integrity of the reburn fuel and burnout air nozzles; minimum requirements for cooling FGR or air were determined during the post-outage timeframe.

Reburn system operation was initially simulated without the use of natural gas to verify operation of the comprehensive control system safety related permissives. Natural gas was injected in small quantities for the first time on August 29, 1990. Full-load automatic operation with 19% natural gas was achieved on September 21, 1990.

10

PARAMETRIC TESTING (ORIGINAL REBURN SYSTEM)

Introduction

This section provides a more detailed description of test results presented by Borio et al. (1991) for the original reburn system, the system which employed flue gas recirculation (FGR) for transport of the natural gas reburn fuel. Borio et al. (1991) and the following subsections show that the original system met the program objectives for NO_x reduction and boiler performance. However, a thick ash deposit formed on the back wall of the furnace during operation of the original reburn system. This ash buildup did not prevent completion of the testing of the original system but was unacceptable for sustained long term operation. The ash buildup is discussed in further detail below in the subsection entitled "Ash Slagging Condition". Action taken to circumvent the ash buildup is discussed in Section 11.

The reburn system incorporated a high degree of operational flexibility for examination and optimization of reburn and boiler operating variables. The primary objective of the parametric testing program was to determine the operational mode which would result in low NO_x (not necessarily lowest NO_x) while minimizing other potentially detrimental effects on boiler performance. These other effects included:

1. Minimizing other gaseous combustible and particulate emissions.

2. Minimizing fuel and auxiliary power costs.

3. Minimizing degradations in boiler performance (e.g., decreases in boiler efficiency, use of reheat attemperator spray, or excessive superheater or reheat steam or tube metal temperatures).

A secondary objective of the parametric testing was to establish a reburn database which could be used to evaluate the process for application to other boilers.

During the initial parametric testing, approximately 150 test points were completed to examine 13 existing boiler and reburn system operational variables. The operational variables examined included:

Baseline Test Variables

- Cyclone Excess Air
- Number of Cyclones in Service
- Boiler Load

Reburn Test Variables

- Reburn Zone
  - Natural Gas Flow Rate
  - Flue Gas Recirculation Flow Rate/Compartment Bias
  - Reburn Fuel Injector Tilt/Yaw Angle
  - Reburn Fuel Injector Horizontal Flow Bias
- Burnout Zone
  - Air Flow Rate
  - Burnout Air Tilt/Yaw Angle
  - Burnout Air and Reburn Fuel Injector Tilt/Yaw Angle Combination

Because of the large number of independent test variables, it was not possible to examine every permutation and combination. The parametric testing was set up and conducted to step-through the variables in a decreasing priority sequence for each of the three key boiler zones (cyclones, reburn zone, and burnout zone). Initially, nominal operating conditions were selected for each variable; then, once a variable had been examined, it was reset to a "near optimum" condition for subsequent tests. Near optimum conditions were selected based on the above testing strategy. The duration of each parametric test was one hour. Several parametric tests were conducted each test day. Typically the reburn system operated continuously during testing times of ten hours per test day. Tests were conducted five days per week over a time period of nine weeks.

To ensure comparability of the results, many tests were repeated. This was necessary because, even though significant effort was expended, it was difficult to replicate cyclone operating conditions on a day-to-day basis. During the parametric testing, a limited number of more comprehensive tests were completed. These were referred to as "maxi" tests. The duration of the maxi tests was eight hours. These tests were run at generator loads of 108 and 86 MWe (net) at baseline (100% coal firing) and 18% natural gas reburn conditions utilizing the reburn configuration found to represent an optimum during the parametric investigations. Purposes of the maxi tests were to:

- Determine the effect of reburn system operation on the furnace gas temperatures entering the reburn zone and the convective pass.
- Assess the effect of reburning on the flue gas conditions entering the electrostatic precipitator (ESP).
- Measure the size distribution and mass loading of the particulates entering the ESP.

- Evaluate the effect of reburn on the collection efficiency of the ESP.
- Carbon in fly ash and bottom ash.

Ohio Edison Niles Plant Coal Analyses

The Eastern bituminous coal fired at the Niles plant arrived by truck from approximately 15 mines located in the Ohio, Pennsylvania, and West Virginia area. No one mine supplied more than 10% of the total coal supply used. Initially there was some concern that coal variability at the Niles plant could add uncertainty to the results and conclusions drawn from those results. However, frequent samples and subsequent analysis of the coal showed the fuel composition to be very consistent. Table 10-1 presents a composite coal analysis based on 21 samples obtained during the first series of parametric tests. Coal analyses are listed in detail in Diskette 1 under the file name COAL.XLS. Statistical data showing the good consistency of the analyses is also shown. Based upon the consistency of the coal compositions, it was concluded that coal variability had a negligible effect on results during this test series.

Table 10-1
Ohio Edison Niles Unit No. 1 Coal Analyses (As-Received Basis)

Proximate Analysis	**Average**	**Maximum Value**	**Minimum Value**	**Standard Deviation**
% Moisture (Total)	7.8	9.3	6.6	0.76
% Volatile Matter	32.2	33.7	31.1	0.62
% Fixed Carbon (By Difference)	47.3	49.3	45.3	0.94
% Ash	12.6	13.6	11.4	0.62
HHV Btu/lb	11576	11870	11277	176
lb Ash/10^6 Btu	10.9	12.0	9.6	0.63
Ultimate Analysis				
% Moisture	7.8	9.3	6.6	0.76
% Hydrogen	4.4	4.5	4.3	0.06
% Carbon	63.4	65.3	61.8	1.11
% Sulfur	3.3	4.1	3.0	0.31
% Nitrogen	1.4	1.5	1.3	0.05
% Oxygen (By Difference)	7.1	8.4	5.5	0.73
% Ash	12.6	13.6	11.4	0.62
Total	100.0			

Baseline NO_x Emissions

NO_x emissions for the subject cyclone-fired boiler at 108 MWe (net) averaged approximately 705 ppm (all NO_x emissions reported have been corrected to a 3% excess O_2 basis). This emissions level was representative of normal operation with a mean cyclone excess oxygen level of 2.0-2.5% O_2 (10.6-13.6% excess air). Slight variations in individual cyclone operation resulted in day-to-day data scatter of approximately ±25 ppm.

Changing the cyclone excess oxygen level changed the NO_x emissions slightly. For example, a 1% decrease in cyclone excess oxygen, from 3 to 2% O_2 decreased NO_x emissions by approximately 15 ppm.

Reducing the cyclone-firing rate also reduced NO_x emissions. At 86 MWe (net), a 20% decrease in boiler load, NO_x emissions under normal operating conditions were approximately 630 ppm, a 75 ppm or 10% decrease in emissions from normal full-load operation. At a reduced boiler load, a similar trend of decreasing NO_x for decreasing cyclone excess oxygen was seen. Baseline NO_x emissions results showing the effects of boiler load and O_2 are shown in Figure 10-1. Data for testing of the original reburn system is listed in electronic media form in Diskette 1 under file name ORIGDATA.XLS..

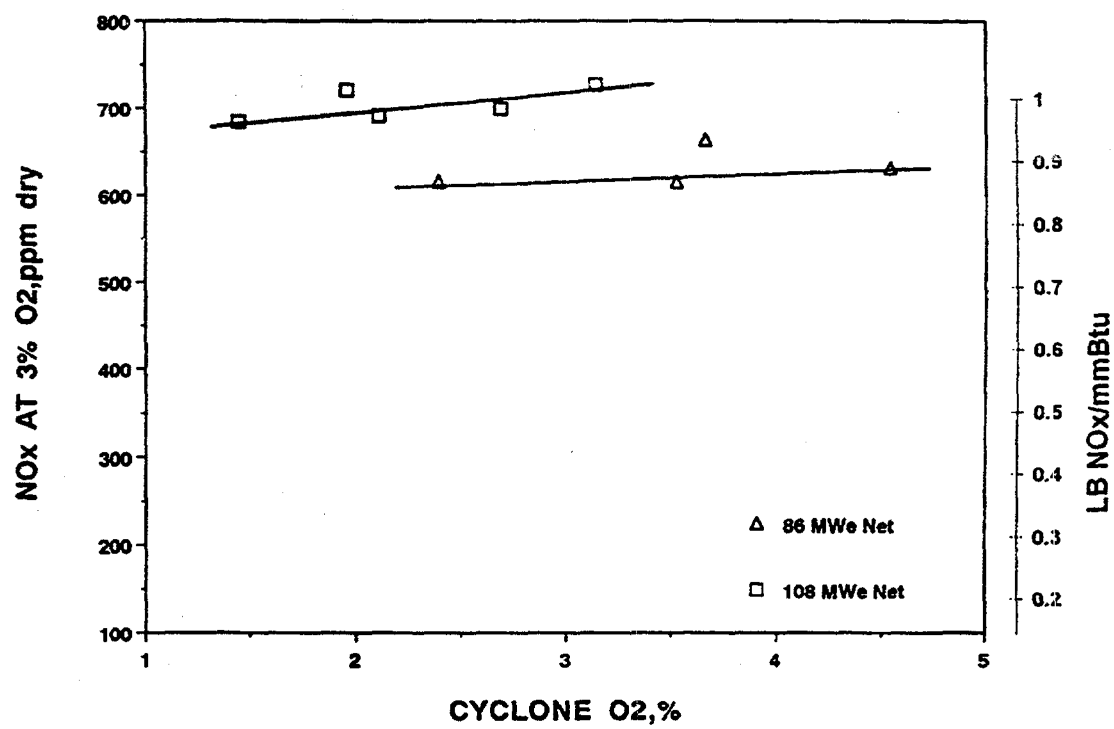


Figure 10-1
Baseline NO_x versus Cyclone O_2, 108 MWe and 86 MWe Net

Carbon monoxide (CO) emissions in the baseline mode of operation were typically very low, under 30 ppm. Baseline SO_x emissions varied between 2400 and 2700 ppm due to slight variations in coal sulfur content. Negligible THC gaseous emissions were observed during baseline and reburn testing.

NO_x Emissions as a Function of Key Variables

Reburn Zone Stoichiometry

Some test variables were found to have a pronounced effect on NO_x emissions, and other variables had little or no effect on NO_x. Reburn zone stoichiometry was found to be the key parameter affecting NO_x emissions. The equations used to calculate reburn zone stoichiometry are discussed in Section 8. Figure 10-2 shows the effect of reburn zone stoichiometry on NO_x emissions. The reburn zone stoichiometry was varied either by adjusting the reburn natural gas flow rate or the cyclone excess air level. For the full-load tests the reburn zone stoichiometry was varied from 0.88 to 1.06.

NO_x emissions are seen to be linearly related to reburn zone stoichiometry (for the test range) and decreased by approximately 180 ppm per 0.10 (or 10%) decrease in reburn zone stoichiometry. For a constant cyclone excess oxygen level an approximate 10% decrease in reburn zone

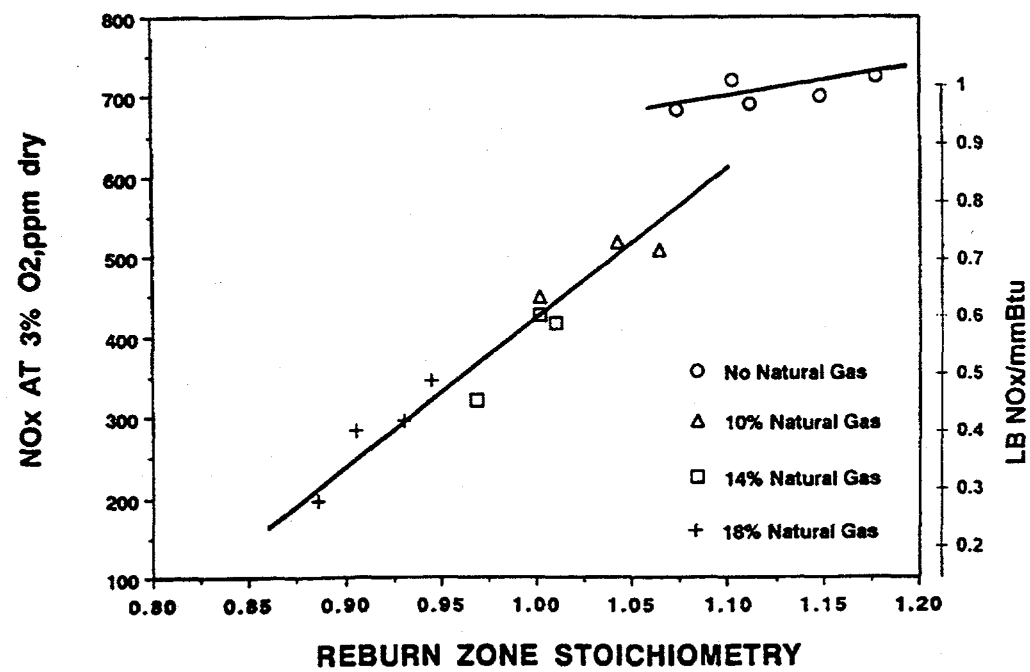


Figure 10-2
NO_x versus Reburn Zone Stoichiometry at Various Gas Flow Rates, 108 MWe, 10% FGR

stoichiometry resulted from a 9% increase in reburn natural gas fuel fraction. For example, with the normal cyclone excess oxygen level of 2.5% O_2 (13.6% excess air), increasing the reburn natural gas fuel fraction from 9 to 18% resulted in a decrease to the reburn zone stoichiometry from approximately 1.03 to 0.93 and a decrease in the NO_x emissions from approximately 480 to 300 ppm (±25 ppm).

Reburn natural gas flow (Figure 10-3) presents the NO_x emissions data versus the amount of reburn natural gas fired. Two significant results shown are: (1) the linearity of the NO_x reduction with increasing natural gas flow for a given cyclone excess oxygen level; and (2) for a given reburn zone stoichiometry (RZS), the NO_x emissions results were similar regardless of whether the stoichiometry was achieved by changing the reburn natural gas flow rate or by changing the cyclone excess oxygen level.

Recirculated Flue Gas Flow

The purpose of flue gas recirculation (FGR) in the reburn system is to assist in the penetration of the reburn fuel and promote mixing of the reburn fuel with the bulk furnace gases without significantly increasing the oxygen content or stoichiometry in the reburn zone as would happen if air were used instead of FGR. Pilot scale research, Farzan, et. al., (1989), has also shown a small incremental NO_x reduction with increasing levels of FGR. Figure 10-4 presents the results of tests where the FGR flow rate was varied from approximately 3 to 11% of the total flue gas flow with constant natural gas flow and reburn zone stoichiometry. Both baseline (no natural gas) and 18% natural gas reburn test series are shown. FGR had no appreciable effect on NO_x emissions with or without reburning.

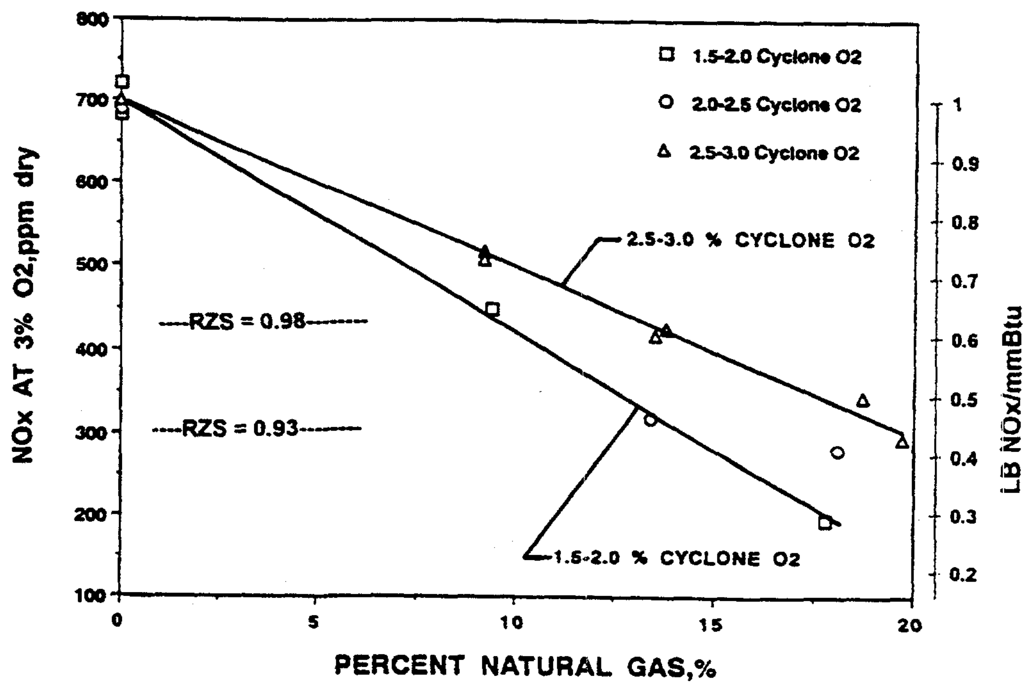


Figure 10-3

NO_x versus Cyclone O_2 at Various Natural Gas Flows and Reburn Zone Stoichiometries, 108 MWe, 10% FGR

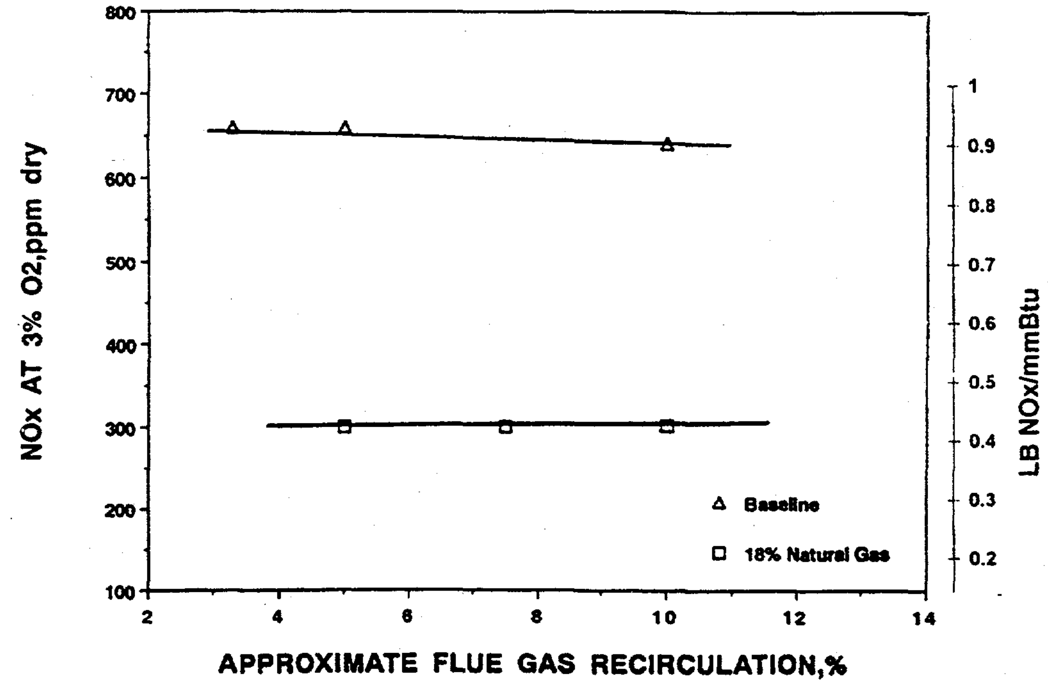


Figure 10-4
NO_x versus Percent Flue Gas Recirculation at Constant Reburn Zone Stoichiometry

The lack of any effect of FGR on NO_x during the baseline (non-reburning) tests was likely due to: (1) coal combustion being essentially completed (no further fuel nitrogen release); and (2) changes in thermal NO_x being not measurably affected because of the relatively low thermal dilution created by introducing FGR (previously measured temperatures showed approximately 2300-2400°F for the reburn zone inlet).

For the reburn tests, varying FGR between 3% and 11%, also had no effect on NO_x emissions. This was likely due to the eventual good mixing that occurred regardless of the FGR flow rate. When FGR was reduced, rapid mixing was likely reduced; but, because of the ample residence time, thorough mixing eventually still occurred and the net result was no change in NO_x emissions. Earlier flow modeling, Borio et al. (1989), had shown that cyclone effluent gases tend to hug the rear wall where the reburn jets were placed. The importance of FGR flow is likely to be very unit specific; e.g., in a large open furnace, if access to the reburn zone is limited, FGR may be required for reburn fuel penetration and thorough mixing.

After determining the sensitivity of NO_x reduction to FGR flow rate it was decided to operate at a reduced level (about 5%) with the FGR fan inlet dampers nearly closed for the remainder of the parametric testing. This was advantageous since lower levels of FGR minimized changes in boiler steam side performance (discussed later) and also decreased auxiliary power consumption. Later in the program, the reburn system was modified to eliminate the use of FGR altogether.

Other Reburn System Variables

NO_x emissions were not directly affected by other reburn system operating variables, including reburn fuel injector tilt, yaw, or flow bias or by burnout air tilt, yaw, or flow bias. However, these variables had a significant effect on CO emissions and the O_2 profile at the air heater inlet. These effects are discussed below.

Reduced Boiler Load Testing

Reduced load testing was conducted at 86 MWe for the following reasons:

- this represents the approximate operating load where the fourth cyclone would be placed into or taken out of service depending on whether boiler load was being increased or decreased.
- 86 MWe baseline coal only tests would have nearly equivalent cyclone loading to the 108 MWe full load tests when full reburn (18% gas heat input) was employed.

Figure 10-5 shows NO_x emissions plotted against reburn zone stoichiometry for both 86 and 108 MWe, net. At reduced load the NO_x values were lower for all conditions than at full load. Reburn effectiveness was also lower. The decrease in NO_x for a ten percent (10%) change in reburn stoichiometry at 86 MWe was approximately 130 ppm compared to the 180 ppm at full load. This decrease in reburn effectiveness is due to lower initial NO_x values and lower gas temperatures which led to slower reactions in the reburn zone.

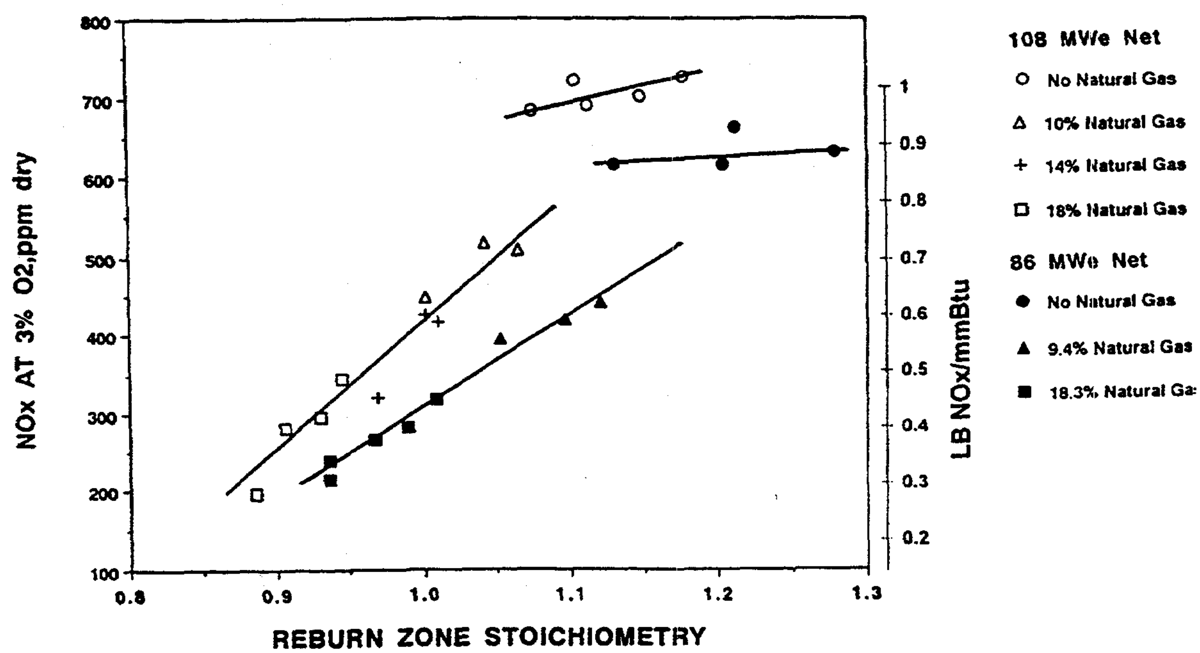


Figure 10-5
NO_x versus Reburn Zone Stoichiometry at Various Gas Flow Rates, 108 MWe and 86 MWe

Other Gaseous Emissions

Baseline emission of CO ranged between 25 and 50 ppm. During shakedown of the reburn system, high levels of CO emissions were observed, especially during high reburn fuel flow rates. The high CO measurements were attributed to insufficient penetration and mixing of the burnout air and occasional maldistribution of air to the cyclones. The airflow distribution to the cyclones was corrected by monitoring oxygen at the sampling ports on the rear wall at an elevation 2'-6" below the reburn fuel nozzles and making required adjustments to the airflow to the cyclones. CO was minimized by down-tilting both the reburn fuel nozzles and burnout air nozzles and optimizing the yaw of the burnout air nozzles. A 17 degree downward tilt of the reburn fuel nozzles and a 10 degree downward tilt of the burnout air nozzles was selected (Figure 10-6). The burnout air nozzles were set to impart a clockwise swirl (viewed from above). With these adjustments CO emissions were decreased to typically below 100 ppm. (Please note that the CO data are presented on a logarithmic scale.) In addition, more uniform CO and O_2 profiles were generated across the boiler exit duct as shown by comparing Figures 10-7 and 10-8.

Emission of SO_2 decreased with increasing natural gas flow as expected. On average the SO_2 decrease was inversely proportional to the reburn fuel flow; however, there was a significant amount of scatter (±10%) due to coal sulfur variations. Gaseous THC emissions were negligible for all tests.

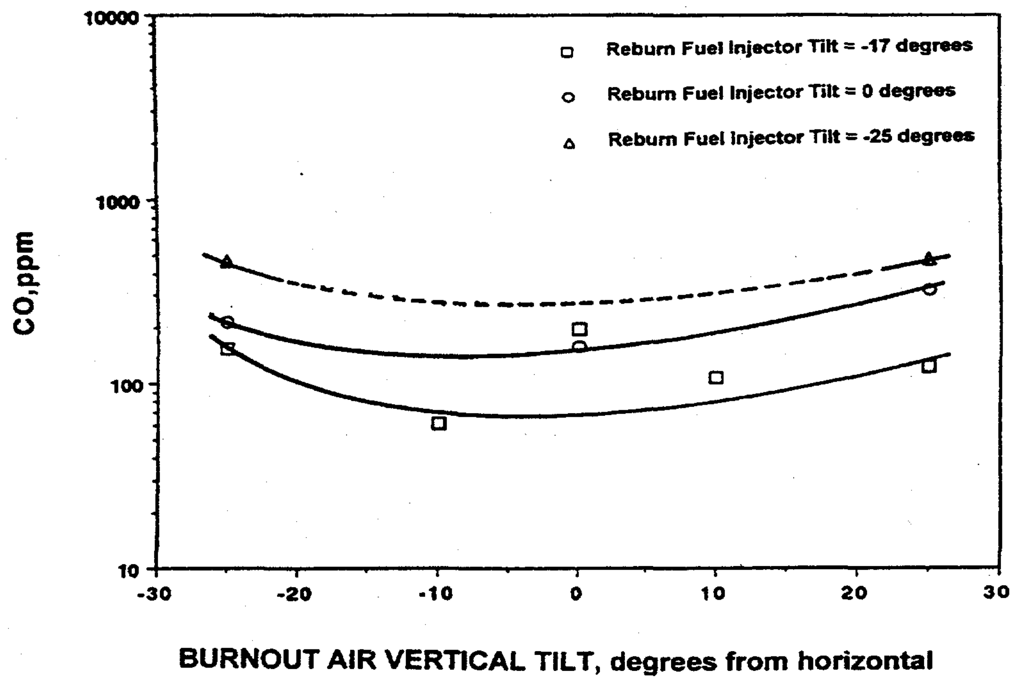


Figure 10-6
CO versus Burnout Air Tilt at Several Reburn Fuel Injector Tilts, 108 MWe Net, 5% FGR, 17.5% Natural Gas, 2.5% Cyclone O_2

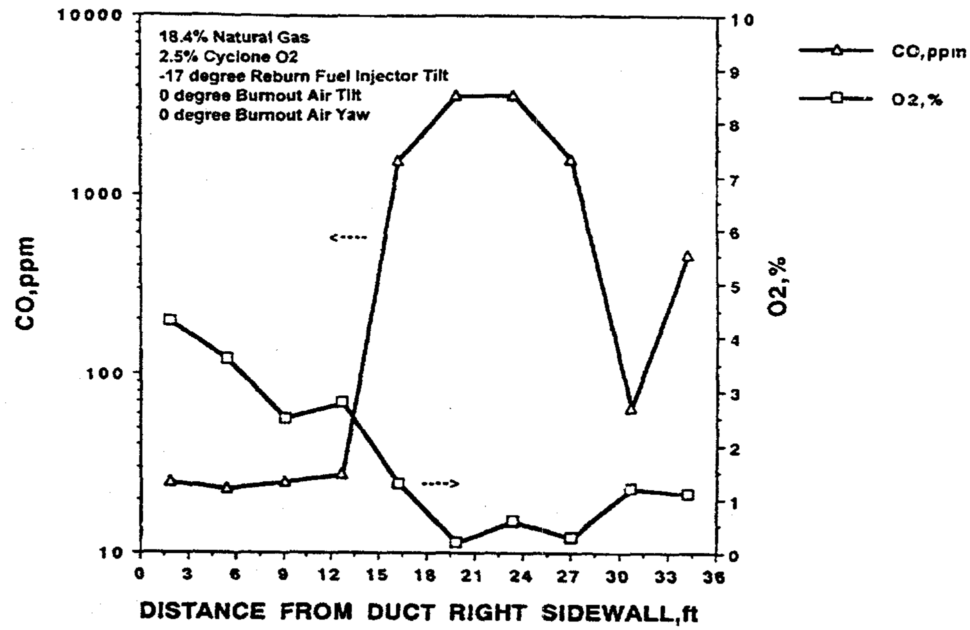


Figure 10-7
O_2 and CO versus Boiler Duct Sample Location, Non-Optimized Operation

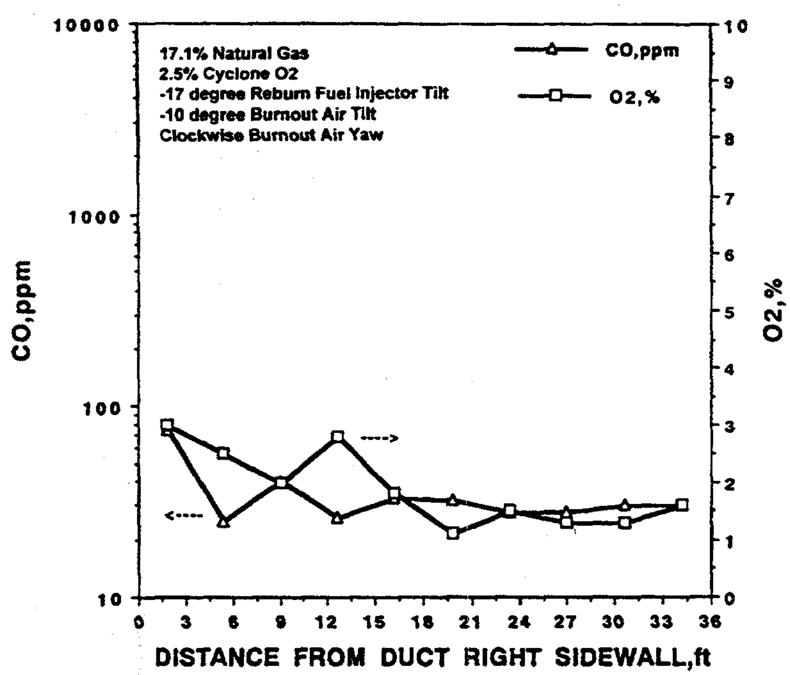


Figure 10-8
O_2 and CO versus Boiler Exit Duct Sample Location, Optimized Operation

Carbon in Ash

Carbon loss in fly ash was not significantly affected by reburning. Fly ash samples were taken and analyzed for approximately two-thirds of the reburn tests. Bottom ash samples were taken once per day. Carbon levels in the fly ash during full-load tests ranged from 25% to 45%, with carbon levels between 30% to 35% being most typical. Attempts were made to relate fly ash carbon level to reburn natural gas flow and cyclone excess air, variables which might be expected to have correlations with fly ash carbon levels. No relationship was found. Carbon in the bottom ash was typically less than 1% of the bottom ash, by weight. Thus for a coal with 12.6% ash and a baseline fly ash/bottom ash ratio of 30:70, the baseline carbon heat loss was approximately 1.2 to 1.4%; and for reburning with a reduced coal flow and hence fly ash loading, the carbon heat loss was approximately 1.0 to 1.2%. Carbon in fly ash and carbon in bottom ash analyses are listed in Diskette 1 under the file name ASH.XLS.

Reasons for the relatively high unburned carbon values under baseline and reburn conditions are unclear. Possible causes include coal properties, coal particle size distribution and cyclone aerodynamics (greater expulsion of coal fines). During reduced load operation the average fly ash carbon content decreased to about 20%. This would be expected with more residence time, decreased cyclone loading, and decreased expulsion of particulate from the cyclones.

Furnace Gas Temperatures

Reburn Zone Inlet Gas Temperatures

Figures 10-9 and 10-10 present results of flue gas temperature traverses made at the inlet to the reburn zone. The furnace depth at the traverse locations was 13 feet. The maximum traverse depth was physically limited to 10 feet. At 108 MWe (net) the baseline average gas temperature was 120°F higher than with 18% reburn. The tests at 86 MWe (net) showed a similar trend: the baseline gas temperature averaged approximately 100°F higher than with reburning. For both the baseline and reburn tests, there was a 200 to 300°F decrease in flue gas temperature from the rear wall to the division wall. The temperature profiles for baseline and reburn at 86 MWe paralleled one another. The baseline and reburn gas inlet temperatures at 108 MWe showed considerable difference near the back wall but approached the same value near the maximum probe insertion measurement depth. Comparison of the average temperatures and profiles measured during the 108 MWe reburn test with the 86 MWe baseline test show very similar results. This is reasonable because the coal loading to the cyclones for reburn with 18% natural gas at 108 MWe is only slightly higher than at 86 MWe with 100% coal.

Furnace Outlet Gas Temperatures

Figure 10-11 shows the results of the temperature traverses from the left (west) side wall at the furnace outlet plane. The traverse depth represents approximately one third of the boiler width. The furnace outlet temperature with reburn averaged 130°F higher at 108 MWe than the base case; i.e., 100% coal. At 86 MWe the average temperature with 18% reburn was about 65°F

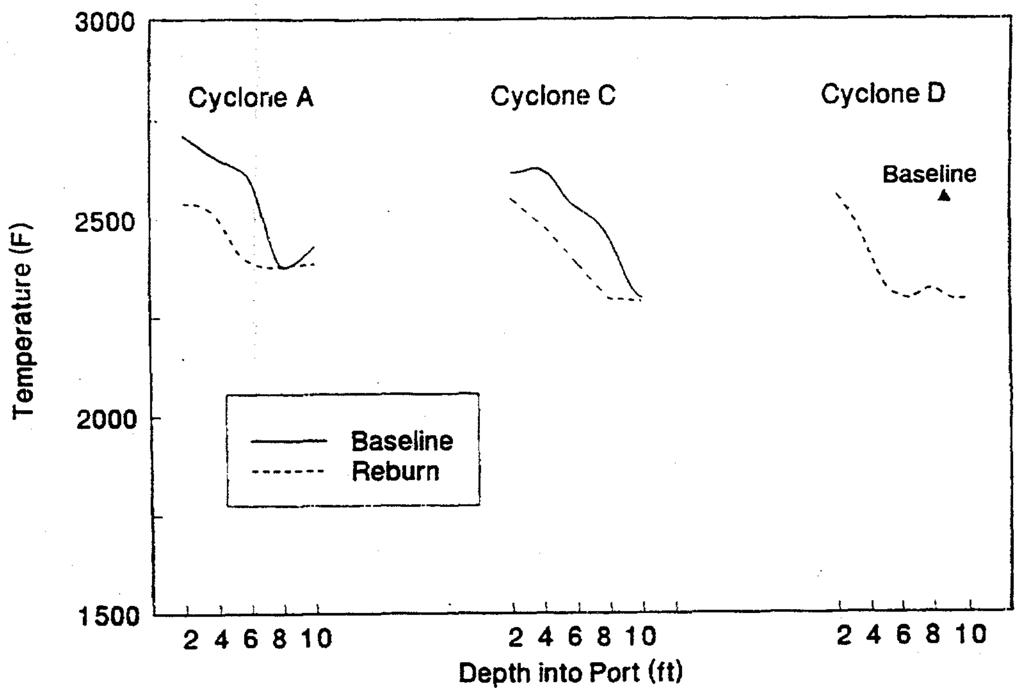


Figure 10-9
Flue Gas Temperatures, Reburn Zone Inlet, 108 MWe Net

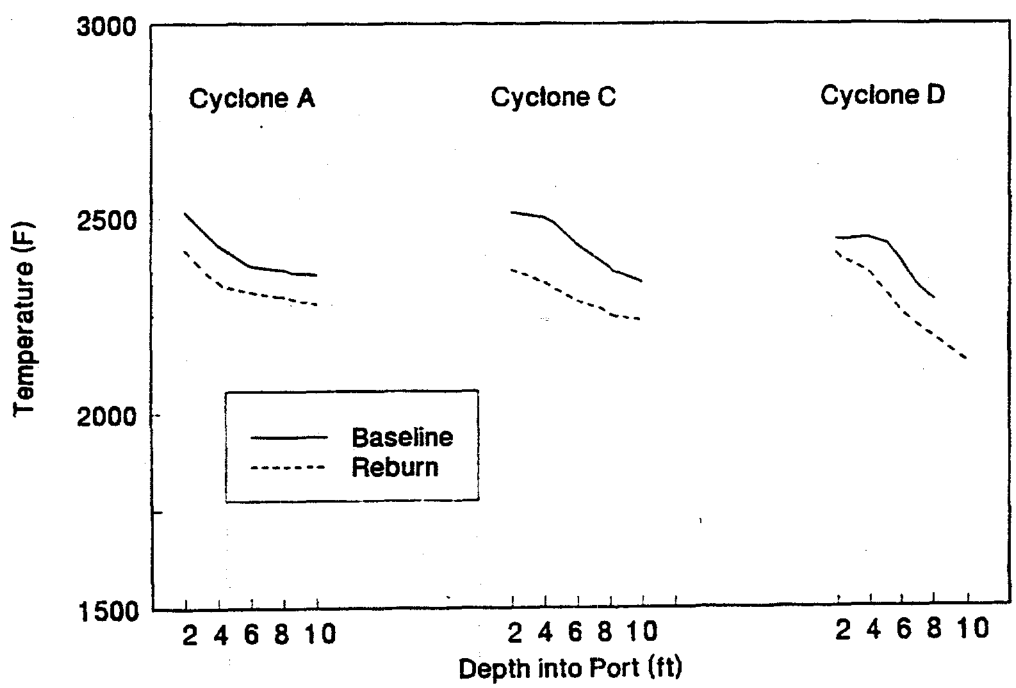


Figure 10-10
Flue Gas Temperature, Reburn Zone Inlet, 86 MWe Net

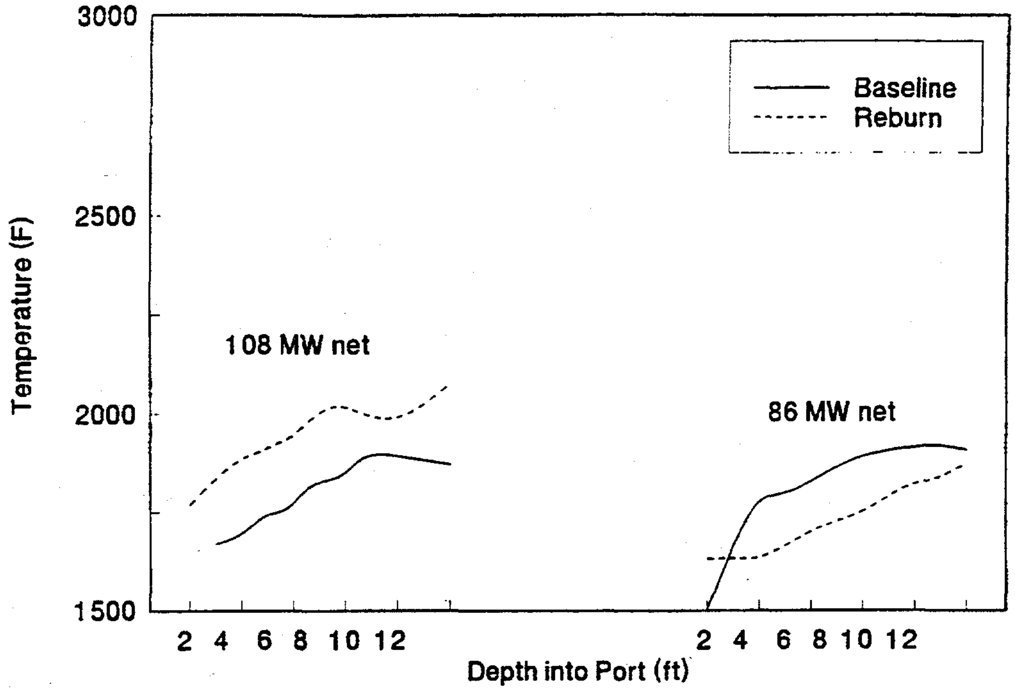


Figure 10-11
Flue Gas Temperature, Furnace Outlet

lower than the baseline temperature. This difference, though generally corroborated by the boiler thermal performance evaluation, is not fully understood.

Electrostatic Precipitator Performance

Electrostatic Precipitators (ESPs) replaced mechanical collectors in the early 1980s to improve particulate collection efficiency. The ESP was sized quite liberally with a specific collection area (SCA) of 278 ft^2/ACFM; it is normally operated with only three of its five fields energized, and operated in this mode an opacity of 2.5% was routinely achieved during parametric testing involving both baseline and reburn testing.

ESP collection efficiency was determined by sampling at the inlet to the ESP in the stack using EPA Method 5. Measurements were made for both the baseline and reburn cases for both full load and 80% load. Results indicated that particulate loading increased with reburn compared to baseline for both full load and part load cases. At 108 MWe the particulate loading was 0.032 lb/10^6 Btu for 100% coal firing and 0.043 lb/10^6 Btu for the full load with 18% natural gas firing. At part load the particulate load was 0.022 lb/10^6 Btu with 100% coal firing and 0.027 lb/10^6 Btu with 18% natural gas firing. Despite the increase in particulate loading in the reburn tests, the loadings were well below the regulatory limit of 0.1 lb/10^6 Btu. Furthermore, it should be possible to duplicate the particulate loading levels measured for the 100% coal firing during reburn operation by optimizing the ammonia injection flue gas conditioning system installed on the unit, as discussed below.

Ammonia was injected into the exhaust duct at a location about ten (10) duct diameters upstream of the ESP inlet port to control acid smut emissions. However, in addition to affecting acid smut emissions, ammonia alters fly ash resistivity and particulate size which in turn can affect ESP performance and particulate emissions, Lookman and Glickert (1992). Ammonia was normally fed at a constant rate, optimized for full base-load operation on 100% coal. At stoichiometric ratios less than unity, ammonia reacts with the SO_3 and water vapor in the flue gas to form ammonium bisulfate (NH_4HSO_4), which is a sticky substance that is believed to be deposited onto fly ash particulates at the flue gas temperatures prevailing in the ESP. During reburn system operation no attempt was made to optimize the ammonia injection system to account for the decrease in the amount of SO_3 entering the ESP. Consequently, the ammonia injection rate was excessive, and the ammonia to SO_3 stoichiometric ratio was above unity. The ammonia then reacted with SO_3 to form ammonium sulfate (NH_4SO_4), which is a crystalline powder at the ESP temperatures. This substance has a high resistivity, making it difficult to collect, unlike ammonium bisulfate that is weakly ionic and actually lowers the fly ash resistivity. Also, unlike ammonium bisulfate, which is sticky and promotes agglomeration of the particulates into larger, easier to collect particulates, ammonium sulfate is formed as a fine powder, that is itself very hard to collect. Therefore, to duplicate the 100% coal firing particulate loading levels leaving the stack it is necessary to optimize the ammonia injection rate of the flue gas conditioning system.

Boiler Thermal Performance

Boiler operating data for four parametric tests of the original reburn system was analyzed to evaluate the effects of reburn on boiler performance. The four tests selected are the following:

Test No.	56A	57B	58A	59C
Date	12/11/90	12/12/90	12/13/90	12/13/91
Load, %	100	100	80	80
Reburn Fuel %	0	17.2	0	18.5
Excess Air %	15.0	14.2	19.6	17.3
Gas Recirculation, %	1.31	4.49	2.08	5.99
Main Steam Temperature,°F	997	1000	1000	1000
Final Reheat Temperature, °F	988	1000	975	982
Reburn Stoichiometry	-	0.94	-	0.99

Two of the tests are with the reburn system shut off (test 56A and 58A) and two are with the reburn system in operation (tests 57B and 59C). Two loads were selected, 100% and 80%. The operating data for these four tests are shown in Table 10-2.

Table 10-2
Niles Unit No. 1 Operating Data

Test No.	56A	57B	58A	59C	Baseline Reference Data
DATE	12/11/90	12/12/90	12/13/90	12/13/90	2/3/88
TIME	822	1811	828	1857	
MATRIX PT	9	58	67	92	
MW (GROSS)	114.5	114.5	92.4	91.7	115
MAIN STM. FLOW K lbs/HR	854.2	843.7	672.2	659.8	840
SH DES. FLOW E lbs/HR	8560	14420	1100	900	
SH DES. FLOW W lbs/HR	1700	23340	10110	11523	
SH DES. FLOW TOT lbs/HR	10260	37760	11210	12430	39000
RH DES. FLOW lbs/HR	0	2320	0	0	0
RH FLOW (EST.) (.887 x MS + SPRAY)	757.7	750.7	596.2	585.2	
FW PRESS PSIG	2051	2061	2234	2247	
DRUM PRESS PSIG	1533	1530	1508	1506	
MAIN STM. PRES. PSIG	1470	1470	1470	1470	1470
RH IN PSIG	336	336	265	261	335
RH OUT PSIG	308	308	241	237	308
STEAM/WATER TEMP. (°F FOR ALL TEMPERATURES)					
FW TEMP.	483.4	483.9	462	460.6	
PRIM. SH OUT. E	748.7	764.9	735.9	730.2	
PRIM. SH OUT. W	722.3	750.5	718.5	716.9	
PRIM. SH OUT. AVG	735.5	757.7	727.2	723.6	750
SEC. SH IN E	706.6	683.1	680.2	673.8	
SEC. SH IN W	728.4	722.3	735.4	731.2	
SEC. SH IN AVG	717.5	702.7	707.8	702.5	691
MAIN STM. E	993.5	1000.1	1000.9	1000.1	
MAIN STM. W	1000.2	999.9	999.6	999.9	
MAIN STM AVG	996.9	1000	1000.3	1000	1000
COLD RH E	672	677	644	642	
COLD RH W	681.5	685.3	659.8	658.1	
COLD RH AVG	681.5	685.3	659.8	658.1	692
COLD RH AFTER DESUPERHEATER	669	668	641	640	692
HT RHO E	990	1002.7	977.7	984.7	
HT RHO W	984	996.6	971.7	978.5	
HT RHO AVG	987.5	999.7	974.7	981.6	990

Table 10-2 (Continued)
Niles Unit No. 1 Operating Data

Test No.	56A	57B	58A	59C	Baseline Reference Data
DATE	12/11/90	12/12/90	12/13/90	12/13/90	2/3/88
GAS/AIR TEMP. (°F)					
GAS LV. PRI. SH E	655	700	600	605	
GAS LV. PRI. SH W	630	660	610	618	
GAS LV. PRI. SH AVG	643	680	605	612	
GAS LV. LT. RH	670	650	645	658	
GAS AHI E	680	688	652	652	
GAS AHI W	680	682	668	672	
GAS AHI AVG	680	685	660	662	747
GAS AHO E	252	248	230	240	
GAS AHO AVG	251	250	233	241	267
AIR AHI	120	118	105	112	130
AIR AHO E	585	590	555	562	
AIR AHO AVG	575	581	554	562	637
PRI. SH. DAMP POS. E	2.12	84.6	-5.28	-5.28	
PRI. SH. DAMP POS. W	0.75	98.8	-0.2	-.23	
RH DAMPER POS.	98.7	-0.78	101.7	101.7	
SPRAY WATER TEMP.	235	236	221	221	
02 AHI %	2.8	2.7	3.5	3.2	
FGR (REBURN) #/HR	13050	44850	17390	48930	
GAS WEIGHT - NO FGR	999800	998100	836000	816200	

With the reburn system off there was still a small amount of gas (1.31% and 2.08% in tests 56A and 58A, respectively) recirculated through the reburn nozzles for cooling. In addition, a small quantity of cooling air was supplied to the burnout air ports. With the reburn system on (tests 57B and 59C), 17.2 and 18.5 percent of the heat supplied to the furnace was from the reburn fuel, respectively. FGR was 4.5% and 6% respectively. Approximate reburn zone stoichiometry was 0.94 and 0.99, respectively.

Using proprietary ABB codes in conjunction with the data in Table 10-2 the following items were calculated:

- Attemperator spray water flows, reheat flow and component heat absorption
- Boiler efficiency and heat supplied to furnace
- Gas and air weights
- Furnace exit gas temperature and gas temperature profile through convection pass
- Secondary superheater surface effectiveness

The results of the thermal performance calculations are summarized in Table 10-3. At full load (114.5MWe, gross) the main impact of reburning on boiler thermal performance was a shift in the heat absorption from the waterwalls to the convective sections. The Niles unit does not have an economizer; therefore, the increase in convective pass absorption was observed in the superheater and reheater. Superheat attemperator spray water flow increased from 1.4% to 3.9% with reburn. A small amount of reheat attemperator spray water was measured (0.26%) during the reburn test, primarily due to leakage past the control valve. Reheater outlet steam temperature was 12°F below design during the baseline test; therefore, reheater performance improved with reburn.

At full load, reburning decreased waterwall heat absorption by approximately 5% and increased the convective section heat absorption by approximately 5%. The decrease in waterwall absorption was due to the decrease in cyclone loading. The increase in convective pass absorption was due to increased gas temperatures (calculated to be 30°F at the furnace outlet plane) and increased flue gas weight (due to FGR) with reburning. Reheater absorption increased by only 4% while superheater absorption increased by 6% due to an adjustment of backpass flow control dampers.

Steam temperature profiles were also monitored during this program. Thermocouples were installed on approximately every fourth tube element at the primary and secondary superheater outlet headers. Negligible changes were observed in primary or secondary superheat profiles between baseline and reburn tests.

Boiler thermal performance for the four tests is summarized in Table 10-3. The boiler efficiency with natural gas reburning decreased by 0.62%. The largest change was a 1% higher loss due to a higher moisture in the flue gas in the reburn cases. The higher moisture in the flue gas is due to the higher hydrogen content in the natural gas versus the hydrogen content in the coal. This loss was somewhat offset by a lower ash pit loss and a lower carbon heat loss due to less coal being fired when reburning was employed.

Table 10-3
Summary Of Boiler Thermal Performance for the Original Reburn System

TEST NO.	56A	57B	58A	59C
TYPE OF TEST	BASELINE	REBURN	BASELINE	REBURN
GROSS MW	114.5	114.5	92.4	91.7
HEAT FROM COAL %	100	82.8	100	81.5
HEAT FROM GAS %	0	17.2	0	18.5
EXCESS AIR %	15.0	14.2	19.6	17.3
GAS RECIRC. %	1.31	4.49	2.08	5.99
STEAM TEMP. SHO-°F	997	1000	1000	1000
STEAM TEMP. RHO-°F	988	1000	975	982
MAIN STM FLOW LBS/HR	854200	843700	672200	659800
REHEAT STM FLOW LBS/HR	757700	750700	596200	585200
SH SPRAY FLOW LBS/HR	11575	32696	9637	10671
RH SPRAY FLOW LBS/HR	0	1959	0	0
GAS RECIRC FLOW LBS/HR	13050	44850	17390	48930
GAS FLOW THRU CONV PASS LBS/HR	1012850	1042950	853390	865130
AIR FLOW THRU AIR HTR LBS/HR	917100	921200	769900	755300
COMPONENT HEAT ABSORPTIONS - MBTU/HR				
PRIMARY SUPERHEATER	124.5	132.6	93.0	89.3
SECONDARY SUPERHEATER	160.7	170.7	132.5	132.8
REHEATER SUPERHEATER	123.2	127.9	98.6	99.4
WATERWALLS	590.3	563.0	478.4	469.7
TOTAL	998.7	994.2	802.5	791.2
HEAT LOSSES - %				
DRY GAS LOSS	2.70	2.66	2.73	2.67
MOIST FROM FUEL LOSS	4.35	5.34	4.38	5.46
MOIST FROM AIR LOSS	0.06	0.06	0.06	0.06
RADIATION LOSS	0.24	0.24	0.29	0.30
ASH PIT LOSS	0.27	0.22	0.27	0.22
CARBON LOSS	1.39	1.15	1.39	1.14
TOTAL	9.28	9.90	9.39	10.06
BOILER EFFICIENCY	90.72	90.10	90.61	89.94
BTU FIRED MBTU/HR	1099.1	1107.7	887.0	881.8
LBS FUEL FIRED	94791	87697	76498	69357
SURFACE EFFECTIVENESS				
SECONDARY SUPERHEATER	0.903	0.907	0.935	0.935
GAS TEMPERATURES - °F				
SECONDARY FURN. OUTLET	2112	2139	2011	1974
REHEATER INLET	1618	1634	1529	1495
REAR CAV. OUTLET	1373	1395	1283	1246
PRIMARY SUPERHEATER INLET	1359	1381	1270	1234
AIR HEATER INLET	680	685	660	662
AIR HEATER OUTLET	251	250	233	241

Comparing data for Tests 58A and 59C shows that the change in thermal performance due to reburn was less noticeable at 80% load. Waterwall heat absorption decreased by 1.8%. Part of this can be attributed to the slightly lower load of Test 59C. Gas temperatures entering the convection pass were lower with reburn, offsetting the effect of increased gas flow. Reheater outlet steam temperature was higher with the reburn system in operation although it was below design. Boiler efficiency was lower with the reburn system in operation as was the case at full load. The boiler efficiency decreased by 0.67%, nearly the same as at full load. Overall, the boiler performance did not change appreciably with natural gas reburning. The minimal changes in boiler efficiency measured during the parametric testing confirm the predicted minimal performance changes as discussed in Section 7.

Ash Slagging Condition

During the planned year-end outage in late 1990 after completion of the parametric testing of the original reburn system, a heavy buildup of slag was found on the rear wall of the furnace at elevations from below the reburn fuel nozzles to above the beginning of the sloping rear wall. The cause of this buildup and resolution of the difficulties caused by the buildup are related to the studded, refractory coated rear wall of the secondary furnace of Niles Unit No. 1. This furnace design, shown in Figure 6-1, includes a primary furnace and a secondary, or main furnace. Hot combustion gases exit from the cyclones, flow downward through the primary furnace, through slag screen tubes, and upward through the secondary furnace. The primary furnace and slag screen are refractory-lined to keep slag discharging from the cyclones in a molten state, permitting the slag to discharge through the slag tap at the bottom of the furnace. In the normal design and operation of screened cyclone furnaces, the tube walls of the secondary furnace are not covered with refractory and there is no running slag above the slag screen. (See Farzan et al. (1993) for a description of the typical screen tube furnace design). However, as discussed in Section 6, Description of the Host Unit, Niles Unit No. 1 (and the sister Unit No. 2) has studded, refractory coated waterwall tubes on the rear wall of the secondary furnace to provide higher gas temperatures in the back pass of the boiler to maintain steam temperatures. During normal operation at Niles a layer of slag builds up on the rear wall due to particles passing through the screen and impacting on molten slag on the rear wall. An equilibrium slag layer thickness of two to four inches is reached with the accumulation of particles impacting and remaining on the wall balancing the flow of slag running down the rear wall. As indicated in Section 6, satisfactory slag tapping and steam temperatures are achieved at Niles with this arrangement over the normal operating range of the unit.

A photograph of the rear wall of the unit and one set of reburn nozzles after completion of the parametric tests is shown in Figure 10-12. The condition of the wall and nozzles, with deposits as much as 12 inches thick at some places near the nozzles, is a sharp contrast to the clean condition of the wall and nozzles before parametric testing, shown in Figure 10-13 prior to accumulating the normal two to four inch equilibrium slag layer buildup that occurs on the rear wall during normal operation. After completion of parametric testing there was speculation that the buildup may have been the result of the natural gas used during the reburn parametric tests. The slag was removed manually and the unit was restarted for a time period without reburn. During this time period flue gas was recirculated to the reburn fuel nozzles at a flow rate equal to approximately 1% of the total flue gas flow rate in order to protect the nozzles from overheating. This flow rate was approximately 20 to 25 % of the flow rate used during reburn tests. After operation in this mode for two (2) weeks, the furnace was again taken out of service and inspected. Slag deposits of about the same size and appearance as those seen after completion of the initial series of reburn parametric tests were again present on the rear wall.

As stated in the Introduction, the Niles No. 1 reburn program was the first full-scale demonstration of reburn technology in the U.S. The condition of the reburn nozzle and rear wall of the furnace seen in Figure 10-12 was not anticipated by any of the small-scale, short-term reburn investigations discussed in Section 5. The experience at Niles clearly shows the importance of long-term demonstration programs as a necessary part in the development of new emissions control technologies. The deposits, which were as much as 12 inches thick, as discussed above, had little or no effect on boiler performance and did not prevent completion of the original system test program. However, long-term operation of the original reburn system was unacceptable for several reasons. Slag falls during boiler operation could have a damaging effect on screen tubes at the bottom of the furnace; the possibility of slag falls during slag removal operation was a risk to personnel; and slag accumulation could cause blockage and misdirection of the reburn fuel jets as well as shorten nozzle life due to overheating. For these reasons there was a need to identify the cause of the problem and to resolve it. These subjects and the redesign of the reburn system are discussed in the next section.

Figure 10-12
Reburn Nozzles and Rear Wall after Completion of Parametric Testing

Figure 10-13
Original Reburn System Nozzles prior to Parametric Testing

11

DESIGN OF REBURN SYSTEM WITHOUT FGR

Analysis of the Slag Buildup Problem

The steps for resolution of the slag buildup problem during the Ohio Edison Reburn Project involved summarization of information that had a bearing on the problem, development of a hypothesis to explain the phenomenon, and resolution of the problem by evaluating the hypothesis. These actions and the modified reburn system design which evolved by resolution of the problem are discussed in this section.

The important information and observations are summarized as follows:

- Deposit removal from the secondary furnace back wall occurs due to molten ash run-off through the screen tubes onto the furnace floor where it is tapped with cyclone slag.
- The deposit on the back wall reaches a steady state thickness when the deposition rate equals the molten slag runoff rate; normal thickness is 2 to 4 inches.
- Following furnace deslagging during the 1990 year-end outage, ash deposition reached pre-outage condition (up to 12 inches thick) in about two weeks time with only reburn nozzle cooling flue gas in operation.
- The sister unit (No. 2) burning the same coal at the same load and excess air had normal ash deposit thickness.
- It is arguable whether the ash deposition was greater with the reburn system in operation or just the FGR system at the flow rate used for cooling the reburn nozzles. However, in either case the buildup was significantly greater than operation without FGR.
- Ash deposition in and around some of the reburn fuel nozzles affected nozzle life.

These observations led to a hypothesis that the heavier than normal ash deposition on the back wall of the secondary furnace was caused by a combination of cooler recirculated flue gas flowing along the back wall, entrained fly ash in the recirculated flue gas, and new studs which were installed on the five new panels (each 3 feet wide by 15 feet high) installed for the reburn fuel nozzles.

The mechanism for reentrainment and redeposition of molten slag droplets is shown diagrammatically in Figure 11-1. The mechanism and slag buildup hypothesis are supported by the following rationale:

- A boundary layer of relatively cool recirculated flue gas flowing along the rear wall caused the deposit temperature on the back wall to decrease.

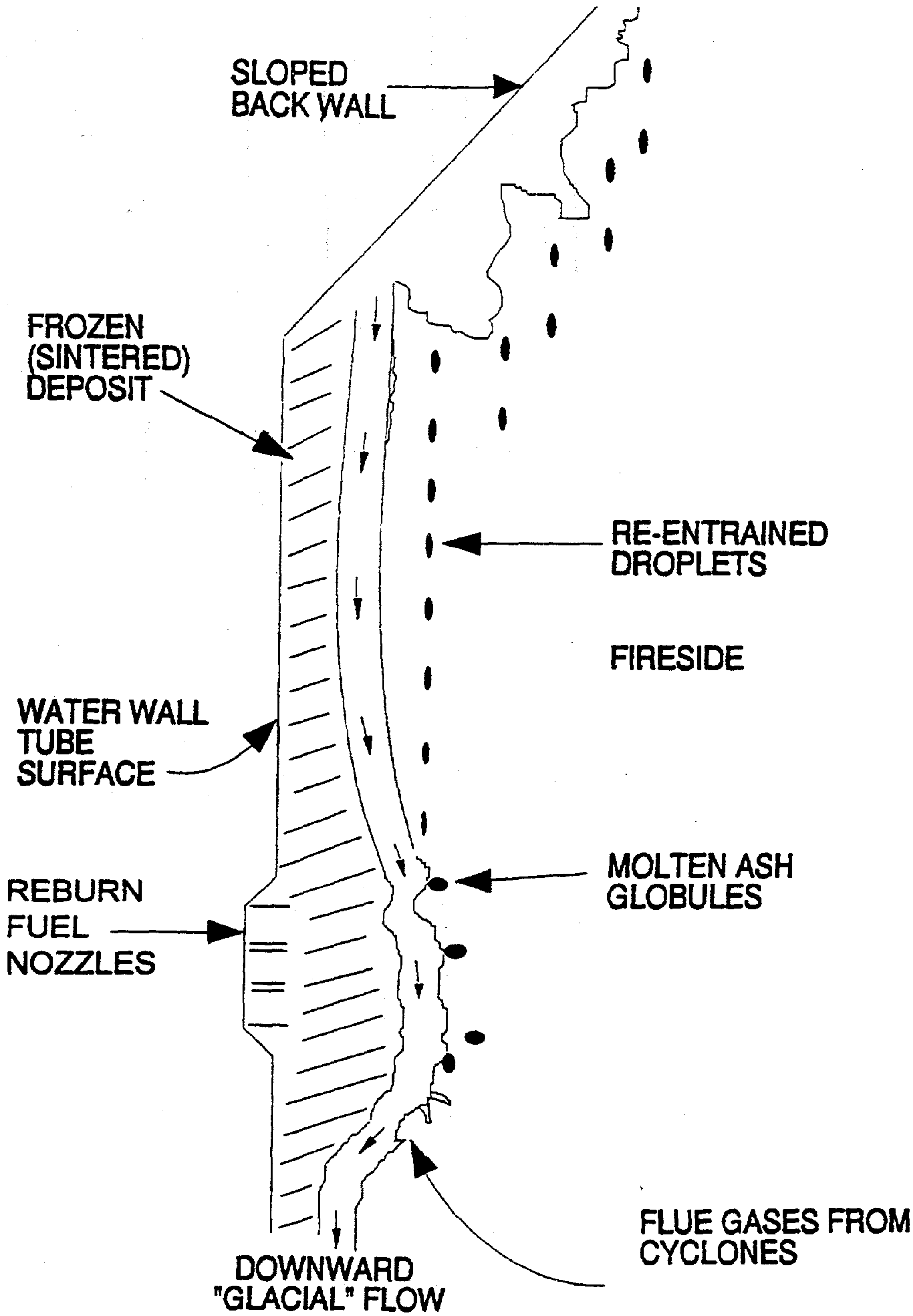


Figure 11-1
Slagging Mechanism at Niles Unit No. 1

-- The decreased deposit temperature forced deposits to grow thicker in order for the surface to reach a sufficiently high temperature for the run-off rate of the slag to equilibrate with the deposition rate.
-- Increased deposit thickness decreased heat transfer in the lower part (vertical wall) of the secondary furnace, thus increasing bulk gas temperature at the upper elevations (sloped wall).
-- Higher bulk gas temperatures coupled with furnace aerodynamics drove more molten, entrained slag droplets into the sloped section of the back wall causing deposition, whereas previously the droplets were frozen or crystallized before impacting the sloping wall. As a result, the sloping wall had thick deposits where previously it only had small islands of deposits one to two inches thick.
-- Fly ash in the recirculated flue gas experienced a different time/temperature history than ash coming directly into the secondary furnace from the cyclones. It was speculated that this might have been a contributing factor in altering the morphology of the deposit from a thin molten deposit to a thicker sintered deposit.

Resolution of the Problem

Several approaches were proposed for resolving the problem. The most attractive approach was to completely eliminate the use of FGR for injection of the reburn fuel. One concern with this approach was possible loss in NO_x removal efficiency due to poorer mixing. In order to address this concern, brief proof of concept (POC) tests were conducted to evaluate the impact of eliminating FGR on NO_x removal. For the POC tests, natural gas injectors were installed temporarily through the four gas sampling ports located on the rear wall at elevation 879'-7" (which is 2'-6" below the center-line of the original reburn fuel nozzles). Tests were run with natural gas flows equal to 6%, 9%, and 12.9% of the total energy input. Results of these tests, given in Figure 11-2, showed little or no difference in NO_x removal compared to reburn tests using 10% FGR at comparable natural gas flow rates. Note that FGR flow rate in the POC tests was less than 1%, the minimum required for cooling the original reburn registers.

Based on these results a decision was made to redesign the reburn system with five water-cooled natural gas injectors installed at the same locations as the original reburn fuel injectors and to use no FGR. The sampling probes were reinstalled at the existing locations. The design of the modified reburn fuel injectors for Niles Unit No. 1 is shown in Figure 11-3. It should be emphasized, however, that the natural gas injectors of the type used at Niles No. 1 may not be optimum for all furnaces because other furnace configurations may require FGR flow to achieve proper mixing of the reburn fuel.

In addition to effective NO_x removal, the modified reburn system had several economic advantages. Changes to pressure parts (water walls) and construction of injectors for the modified system were less costly. The elimination of the gas recirculation fan, controls, and ducts represented a reduction in capital, maintenance, and operating costs. The space and time requirements for the reburn system were also reduced.

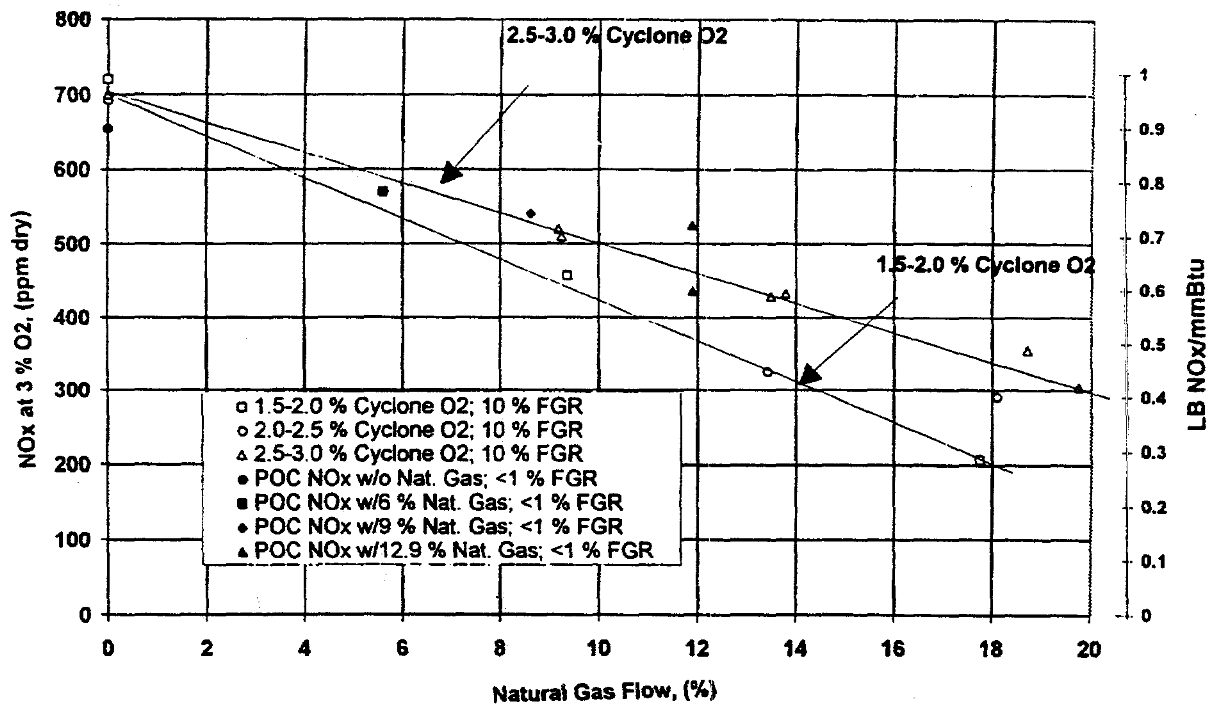


Figure 11-2
NO_x Emissions at 108 MWe for POC Tests Compared to Tests with 10% FGR

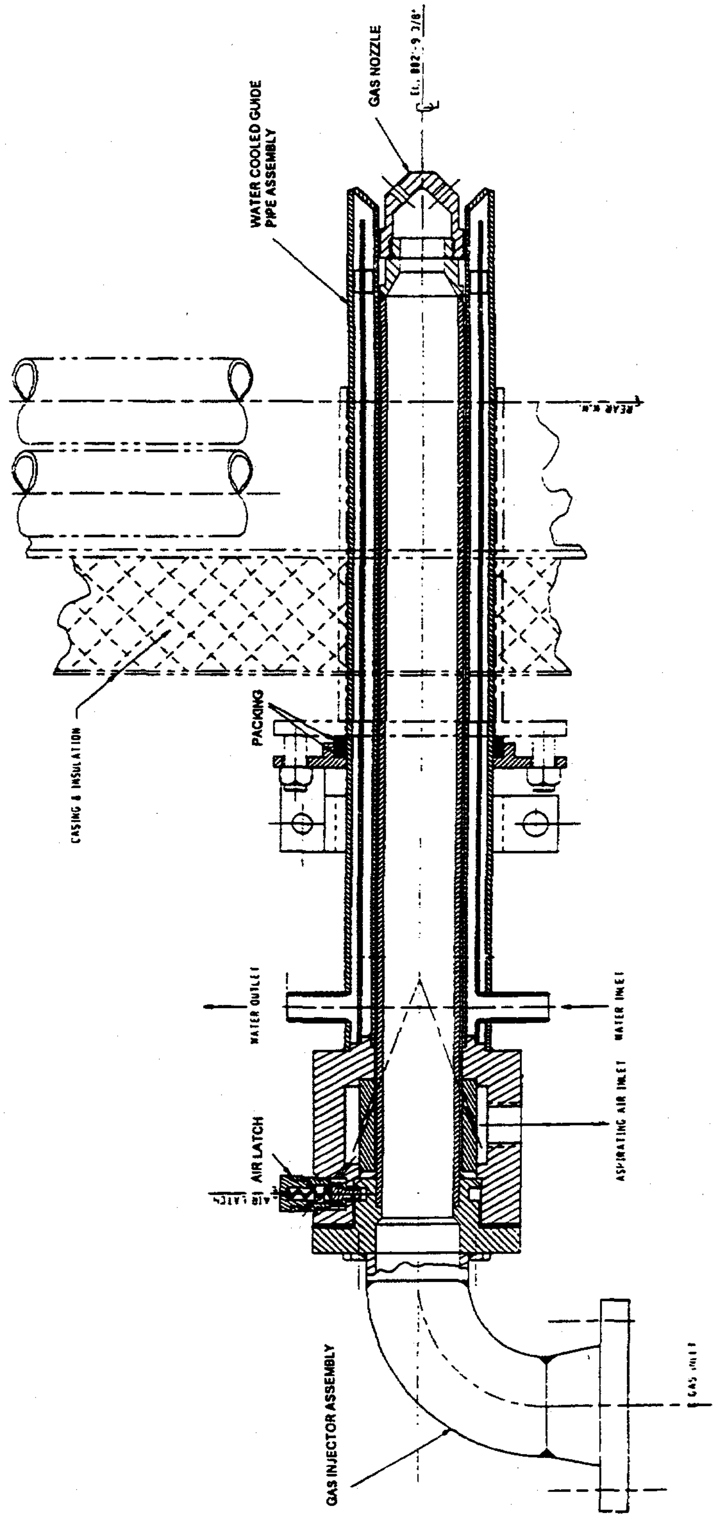


Figure 11-3
Natural Gas Injector for the Modified Reburn System

12

PARAMETRIC TESTING (MODIFIED REBURN SYSTEM)

Introduction

After installation of the modified reburn system, parametric tests were run to measure emissions and thermal performance of the system, to establish reburn system operating characteristics, and to identify optimized reburn system operating parameters for long-term load dispatch testing. These parametric tests were conducted between October 29, 1991 and November 20, 1991. A limited number of measurements of water feed to the reburn zone were obtained in January 1992 when two water-cooled guide-tubes inadvertently developed water leaks. Controlled parametric tests of water injection to the reburn zone for enhancing system performance were performed in July 1992. The results of parametric tests and conclusions concerning modified system emissions control performance are discussed in this section.

Modified System Emissions Performance and Operating Characteristics

Full load NO_x emissions for the original and modified reburn system are shown in Figure 12-1. A detailed data summary for the modified reburn system is given in electronic media form in Diskette 1 under the file name MODSYS.XLS. A comparison tabulation of NO_x and CO emissions for full-load parametric testing of the original reburn system, the modified reburn system, and the modified reburn system with water injection (discussed later in this section) is given in Table 12-1. The modified reburn system NO_x emissions were 50 to 75 ppm higher than the original system at a given reburn system stoichiometry. The NO_x emissions reduction of the modified system did, however, satisfy the program emission control goal of 50% NO_x emissions reduction at full load during the parametric testing. Reasons for the lower NO_x reduction with the modified system during parametric testing were unclear, and indeed, later long-term results with the modified reburn system (June 1992) were essentially the same as those with the original system. Possible reasons for the different performance noted during parametric testing are discussed in further detail below.

The modified reburn system was more sensitive to CO formation than the original reburn system. Figure 12-2 gives a plot of CO versus NO_x emissions for the original reburn system and the modified system. CO levels for the modified system increased from nominal levels of 50 to 100 ppm to 700 to 800 ppm as NO_x levels decreased to 325-350 ppm. The "knee" of the CO curve was lower for the original reburn system where NO_x levels were reduced to 300 ppm before significant CO levels were reached.

Table 12-1
Full Load Parametric Test Emissions Measurements for the Original Reburn System, Modified System, and System with Water Injection

	Original System						Modified System				
Test No.	Gross Load (MW)	Avg AHin NOx (ppm@3%)	Avg AHin CO (ppm)	NOx Red. (707 Base) (%)	Reburn Zone Stoich.	Test No.	Gross Load (MW)	Avg AHin NOx (ppm@3%)	Avg AHin CO ppm	NOx Red. (707 Base) (%)	Reburn Zone Stoich.
N1-27C	116.0	345	255	51.2	0.945	N1-102C	114.93	402	40	43.1	0.946
N1-27D	116.0	347	60	50.9	0.955	N1-102D	115.15	399	54	43.6	0.925
N1-27E	116.2	417	22	41.0	1.010	N1-103C	115.32	421	58	40.5	0.899
N1-27F	114.9	517	37	26.9	1.064	N1-104B	114.99	562	20	20.5	1.032
N1-30B	113.5	320	783	54.7	0.969	N1-104C	115.22	371	139	47.5	0.919
N1-31B	116.7	448	121	36.6	1.002	N1-104D	114.99	347	292	50.9	0.903
N1-31C	115.2	282	550	60.1	0.906	N1-104E	112.18	308	759	56.4	0.909
N1-32C	116.0	508	28	28.1	1.042	N1-105B	115.72	473	45	33.1	0.990
N1-32D	114.0	426	40	39.7	1.002	N1-105C	114.54	319	725	54.9	0.911
N1-32E	113.6	365	22	48.4	1.014	N1-105D	115.45	323	681	54.3	0.913
N1-32F	114.2	295	114	58.3	1.025	N1-105E	115.89	373	145	47.2	0.951
N1-34C	116.4	303	686	57.1	0.974	N1-106B	115.88	340	276	51.9	0.932
N1-34D	115.3	301	773	57.4	0.938	N1-106C	114.95	353	359	50.1	0.922
N1-34E	114.5	301	380	57.4	0.946	N1-106D	115.35	556	20	21.4	1.053
N1-35B	114.9	305	1068	56.9	0.931	N1-108A	116.10	351	347	50.4	0.923
N1-35C	114.7	298	1095	57.9	0.921	N1-108B	116.26	476	38	32.7	0.996
N1-35D	115.4	295	790	58.3	0.942	N1-108C	116.67	581	32	17.8	1.076
N1-35E	115.0	272	1136	61.5	0.925						
N1-35F	115.8	275	1501	61.1	0.917						
N1-36A	114.5	304	692	57.0	0.935						
N1-36B	114.9	288	1324	59.3	0.918						
N1-36C	113.9	283	354	60.0	0.914						
N1-36D	113.9	301	180	57.4	0.913						
N1-37B	114.5	405	24	42.7	0.977						
N1-37C	115.1	356	85	49.6	0.959						
N1-38C	116.1	368	61	47.9	0.959						
N1-39B	113.5	382	33	46.0	0.986						
N1-39C	115.4	337	408	52.3	0.947						
N1-41B	115.4	355	42	49.8	0.946						
N1-41C	115.6	337	72	52.3	0.936						
N1-42B	112.7	302	94	57.3	0.946						
N1-43B	114.6	325	196	54.0	0.941						
N1-43C	115.8	328	154	53.6	0.928						
N1-43D	115.1	337	62	52.3	0.940						
N1-43E	115.4	334	108	52.8	0.947						
N1-43F	115.9	339	122	52.1	0.954						
N1-45B	114.6	292	364	58.7	0.949						
N1-46B	114.9	303	507	57.1	0.937						
N1-46C	114.9	268	468	62.1	0.928						
N1-46D	115.6	291	477	58.8	0.932						
N1-46E	116.2	301	325	57.4	0.946						
N1-47A	115.7	288	157	59.3	0.956						
N1-47B	115.6	302	218	57.3	0.949						
N1-47C	114.1	288	649	59.3	0.943						
N1-47D	116.7	306	205	56.7	0.996						
N1-47E	114.1	306	133	56.7	0.949						
N1-47F	116.2	291	246	58.8	0.944						
N1-48B	115.0	310	59	56.2	0.949						
N1-48C	115.6	311	126	56.0	0.942						
N1-48D	115.1	333	35	52.9	0.946						
N1-48E	115.1	321	101	54.6	0.937						
N1-48F	114.8	295	53	58.3	0.930						
N1-48G	114.5	292	85	58.7	0.924						
N1-49A	115.2	288	69	59.3	0.945						
N1-49B	116.0	295	239	58.3	1.001						
N1-50B	116.5	276	483	61.0	0.951						
N1-50C	115.0	283	488	60.0	0.979						
N1-57B	114.5	382	26	46.0	0.990						
N1-60B	114.5	281	356	60.3	0.959						
N1-60C	114.6	453	29	35.9	1.038						
N1-61B	114.5	303	14	52.0	0.954						
N1-61C	114.7	324	15	48.6	0.957						
N1-61D	113.5	330	14	47.9	0.941						

Table 12-1 (Continued)
Full Load Emissions Measurements for the Original Reburn System, Modified System, and System with Water Injection

	Modified System with Water Leak						Modified System with Water Injection				
	Gross Load	Avg AHin NOx	Avg AHin CO	NOx Red. (707 Base)	Reburn Zone		Gross Load	Avg AHin NOx	Avg AHin CO	NOx Red. (734 Base)	Reburn Zone
Test No.	(MW)	(ppm@3%)	ppm	(%)	Stoich.	Test No.	(MW)	(ppm@3%)	ppm	(%)	Stoich.
110A	113	308	907	56.4	0.966	126H	114	273	157	62.8	0.908
111C	113	269	508	62.0	0.96	126H2	114	312	57	57.5	0.916
111D	114	233	1771	67.0	0.937	126I2	113	314	57	57.2	0.918
111E	115	298	1243	57.9	0.946	126K	114	322	46	56.1	0.917
						127C	114	334	56	54.5	0.935
						127D	115	318	75	56.7	0.936
						127E	114	324	44	55.9	0.938
						127F	114	323	35	56.0	0.943
						129B	114	325	48.2	55.7	0.964
						129C	115	304	38	58.6	0.924
						129D	114	335	28	54.4	0.945
						129E	115	322	45	56.1	0.930
						129F	114	332	40	54.8	0.917
						130AR	114	307	71	58.2	0.961
						130B	114	345	43	53.0	0.954

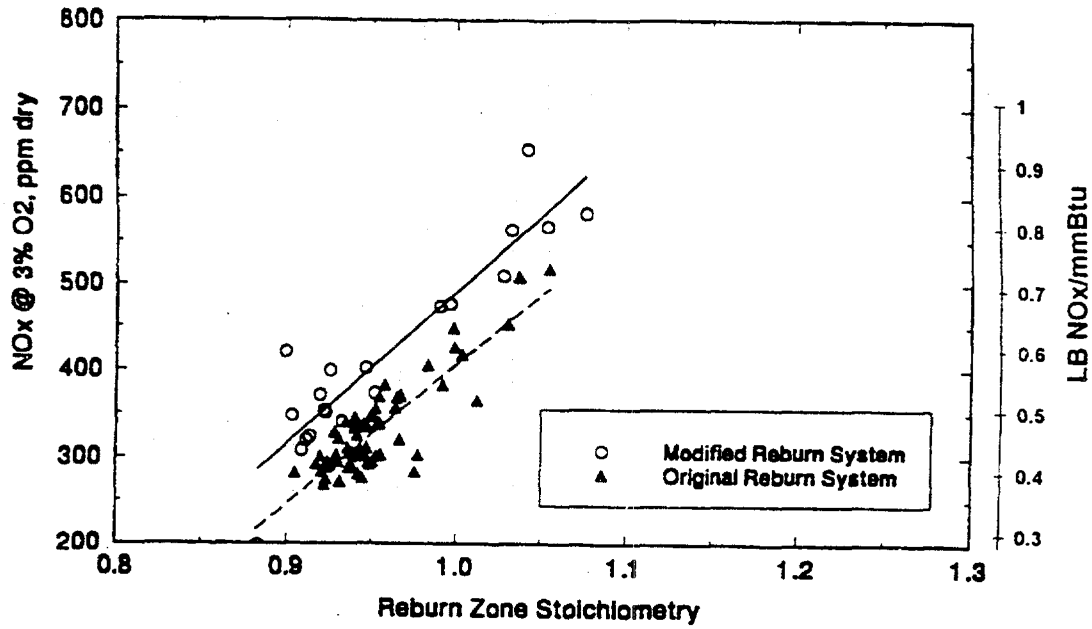


Figure 12-1
Original and Modified Reburn System NO_x Emissions at Full Load

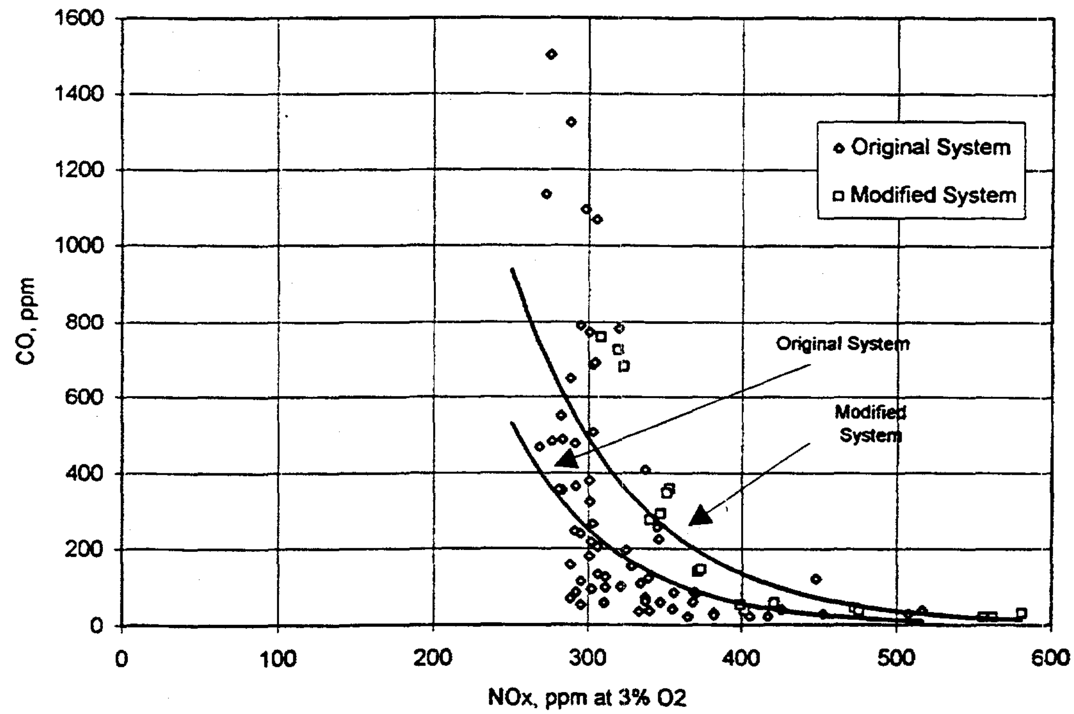


Figure 12-2
NO_x-CO Emissions Comparison for the Original System and Modified System at Full Load

Another difference between the two reburn systems was the presence of greater luminosity in the reburn zone during operation of the modified system. The luminosity was seen through observation ports located on the side walls on the operating floor (Elevation 870'-0") and primarily by a video camera located on a side wall on the operating floor. Although there was no video camera installed during tests of the original reburn system, visual observation did not appear to show the same degree of luminosity. The luminosity observed during operation of the modified system suggested that the chemical environment was somewhat different in the reburn zone between the two systems. This difference is discussed in further detail below.

Differences in operating characteristics were observed. The heavy build-up of slag on the rear wall was eliminated by elimination of the FGD system. Elimination of FGD simplified operation of the reburn fuel feed system since a flue gas recirculation fan can be a relatively high maintenance piece of equipment. Also, capital costs for commercial installations of reburn systems will be reduced by elimination of the flue gas fan and associated ductwork and controls.

Elimination of FGD and the thick coating of slag on the rear wall returned the boiler operation and thermal performance back more closely to the mode that existed under baseline conditions. The thermal performance of the modified reburn system is compared to baseline performance for both full load and part load in a subsection below.

Modified System Optimization Tests

Although the modified system achieved the objectives of eliminating the excessive buildup of slag on the rear wall while maintaining acceptable NO_x reduction performance and good system operability, the interest in bringing the NO_x reduction performance up to the level of the original reburn system remained. Therefore a series of tests was conducted to optimize the reburn system fuel injector configuration and operating parameters and to evaluate NO_x emissions reduction at reduced loads. The results of these tests are discussed in this subsection.

Variation in Aspirating Air Flow Rate and Gas Nozzle Tip Arrangement

The natural gas injector design (Figure 11-3) provided for use of aspirating air as a precaution to protect against slag build-up on the gas injector tips. Tests were conducted to evaluate the effect of aspirating air flow on tip slagging and NO_x emissions. In addition, tests were conducted with the gas nozzle tips removed to evaluate the effect of nozzle area and hence natural gas injection velocity on reburn effectiveness. Results of the testing are shown in Figure 12-3. Turning off the aspirating air had a minimal impact on tip slagover since slagover was not found to be a problem with or without aspirating air. NO_x emissions were lower at a given RZS with the aspirating air off. Therefore, this air was left off in the optimized modified reburn system configuration. Figure 12-3 also shows that NO_x emissions performance was about the same with the nozzle tips in place or removed.

Position of Gas Injectors

The injector nozzle design provided capability for varying the insertion depth of the nozzle tips. Figure 12-4 shows no consistent effect of nozzle retraction on NO_x reduction.

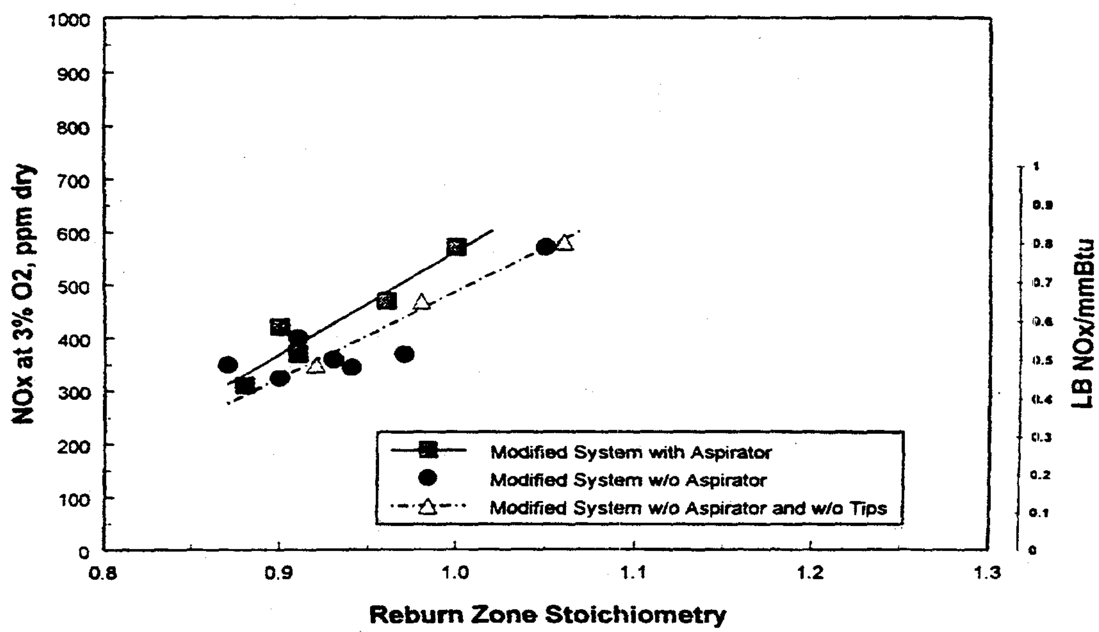


Figure 12-3
NO_x Emissions for Variations in Aspirating Air Flow Rate and Gas Nozzle Tip Arrangements

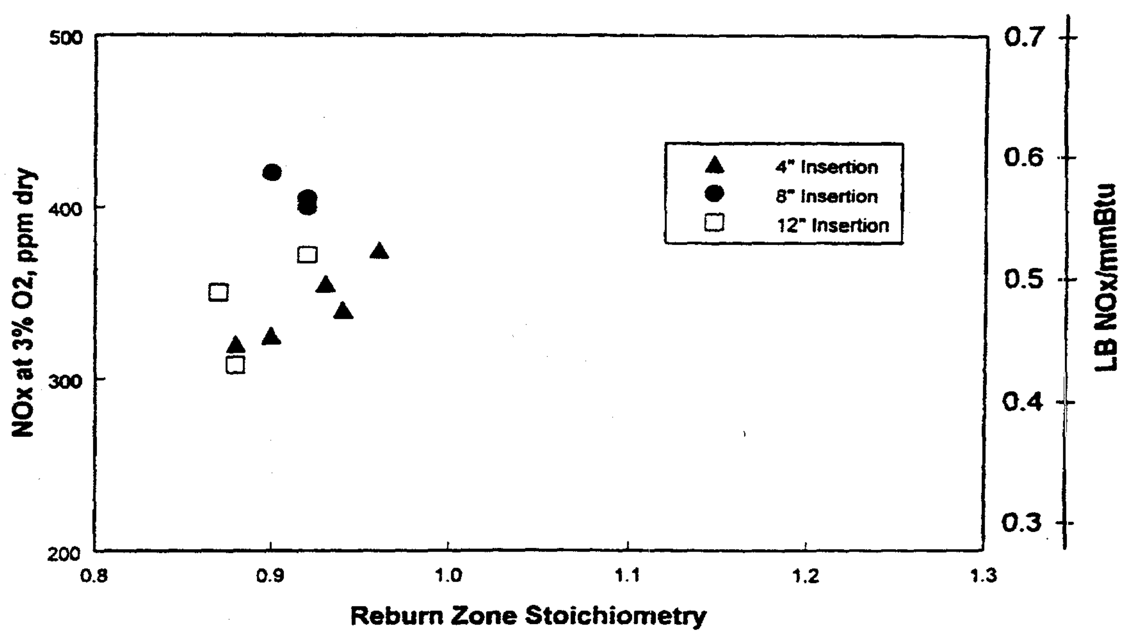


Figure 12-4
NO_x Emissions for Variations in Gas Injector Position

Natural Gas Feed Rate

Tests of the modified system with 20 percent reburn gas consistently resulted in higher CO than tests with 18 percent reburn gas. No difference in NO_x emissions was found between these conditions. In order to maintain CO within acceptable limits during long-term tests, the natural gas flow and corresponding RZS were limited to the flow corresponding to 16% of the total energy input.

Reduced Load Parametric Tests

Figure 12-5 shows NO_x emissions for the modified reburn system at 86 MWe. The highest emissions reduction is 35.5%. As with the original reburn system, a decrease in reburn effectiveness was found at part load. The reduced reburn effectiveness was due to lower initial NO_x values and lower gas temperatures in the reburn zone, leading to slower reburn chemical kinetics.

Reburn System Configuration and Operation for Long-Term Dispatch Testing

Based on the results of the parametric tests of the modified system, the following reburn system parameters were selected for the long-term dispatch testing:

- No aspirating air
- No tips for the natural gas injectors
- Natural gas injectors inserted four inches from the furnace walls
- Maximum natural gas flow rate equal to 16% of the total fuel input.

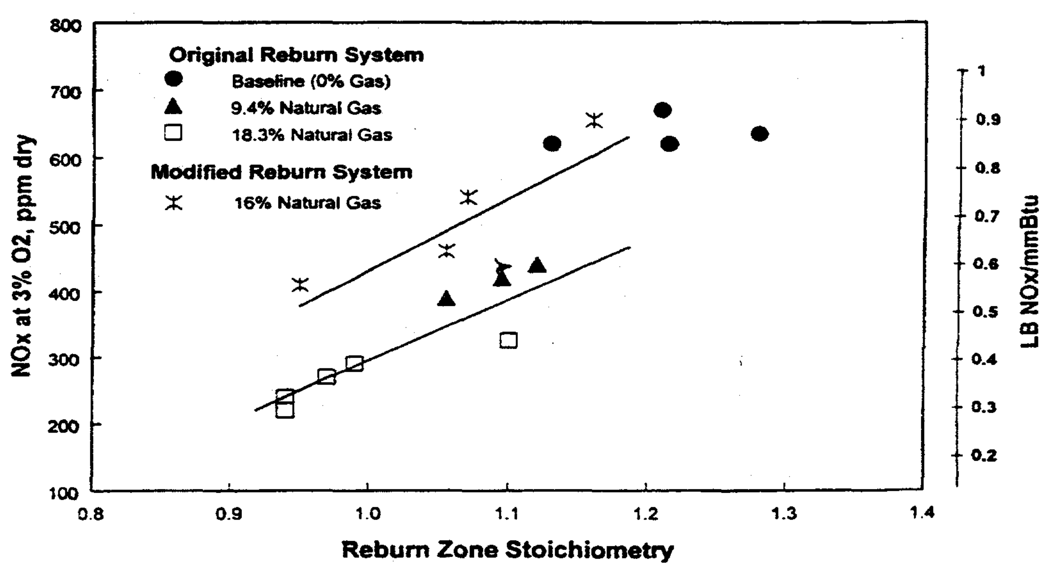


Figure 12-5
NO_x Emissions for the Original Reburn System and Modified Reburn System at 86 MWe

Modified System Thermal Performance

Boiler operating data from four tests with the revised reburn system was analyzed to determine the effect of the revised reburn system on boiler thermal performance with and without the reburn system in operation. The four representative tests selected for study are the following:

Test No.	106A	106B	109E	109A
Time	1020	1155	2340	2005
Date	11-6-91	11-6-91	11-20-91	11-20-91
Type of Test	Baseline	Reburn	Baseline	Reburn
Load - %	100	100	79	79
Reburn Fuel %	0	18	0	18
Excess Air %	9.2	11.9	24.5	21.4
Main Steam Temp °F	952.6	1000.4	966.8	957.4
Final Reheat Temp °F	925.0	981.8	924.2	920.0
Reburn Stoichiometry	-	0.93	-	0.98

As was the case with the original system, two of the tests were with the reburn system on and two were with the system shut off (see table above). One pair of tests was at full load and the other pair at 79% of MCR. The operating data for these four tests is shown in Table 12-1. Approximate reburn stoichiometry was 0.93 and 0.98 for the two reburn tests.

Table No. 12-2
Operating Data

Test No..	Baseline 106A	18% Reburn 106B	18% Reburn 109A	Baseline 109E	Baseline Reference Data
DATE	11-6-91	11-6-91	11-20-91	11-20-91	2/3/88
TIME	1020	1155	2005	2340	
MW (GROSS)	114.4	115.9	91.0	90.3	115
MAIN STM. FLOW K lbs/hr	901.3	877.4	684.5	676.9	840
SH DES. FLOW E lbs/hr	0	0	0	0	
SH DES. FLOW W lbs/hr	0	2000	0	0	
SH DES. FLOW TOT lbs/hr	0	2000	0	0	39000
RH DES. FLOW lbs/hr	0	0	0	0	0
RH FLOW (EST.) (.887 X MS + SPRAY)	799453	778254	607152	600410	
FW PRESS psig	1854	1883	2127	2136	
DRUM PRESS psig	1538	1538	1508	1508	
MAIN STM. PRES. psig	1470	1470	1470	1470	1470
RH IN. psig	348.4	346.5	266.8	264.5	335
RH OUT psig	NA	NA	NA	NA	308
STEAM/WATER TEMP. (°F)					
FW TEMP.	486.8	488.2	464.3	463.9	
PRIM. SH OUT. E	713.5	736.6	694.5	705.9	
PRIM. SH OUT. W	681.5	709.4	696.3	693.0	
PRIM. SH OUT. AVG	697.5	723.0	695.4	699.5	750
SEC. SH IN E	670.6	697.8	680.4	676.8	
SEC. SH IN W	718.6	737.3	698.4	710.7	
SEC. SH IN AVG	694.6	717.5	689.4	693.7	691
MAIN STM. E	961.0	996.81	953.99	973.81	
MAIN STM. W	944.32	1004.0	961.0	959.8	
MAIN STM. AVG	952.6	1000.4	957.43	966.8	1000
COLD RH E	NA	NA	NA	NA	
COLD RH W	641.7	684.8	621.7	629.0	
COLD RH AVG	641.7	684.8	621.7	629.0	692
COLD RH AFTER DES.	641.7	684.8	621.7	629.0	692
HT RHO E	928.1	984.87	922.5	927.1	
HT RHO W	922.0	978.9	917.4	921.3	
HR RHO AVG	925.0	981.8	920.0	924.2	990

Table No. 12-2 - Cont'd.
Operating Data

Test No.	Baseline 106A	18% REBURN 106B	18% Reburn 109A	Baseline 109E	Baseline Reference Data
GAS/AIR TEMPERATURES (°F)					
GAS LV. PRI. SH E	612	627	581	600	
GAS LV. PRI. SH W	609	616	599	614	
GAS LV. PRI. SH AVG	610.5	621.5	590.0	607	
GAS LV. LT. RH	635	645	612	633	
GAS AHI E	653	667	618	636	
GAS AHI W	663	681	634	652	
GAS AHI AVG	658	674	626	644	747
GAS AHO E	246	249	230	236	
GAS AHO AVG	246	249	230	236	267
AIR AHI	127	127	125	134	130
AIR AHO E	554	556	534	544	
AIR AHO AVG	554	556	534	544	637
PRI. SH. DAMP POS. E	21.09	33.92	9.108	9.108	
PRI. SH. DAMP POS. W	0.72	1.22	8.68	8.64	
RH DAMPER POS.	11.20	11.20	11.20	11.20	
SPRAY WATER TEMP. (°F)	295.1	295.1	284.5	283.9	
02 AHI % (FROM ESA)	1.8	2.3	3.8	4.2	
FGR (REBURN) lbs/hr	0	0	0	0	
GAS WEIGHT - NO FGR lbs/hr	964700	995100	835100	843000	

Based on test data the following items were calculated:

- Component heat absorptions
- Boiler efficiency
- Heat supplied to the furnace
- Gas and air weights
- Furnace exit gas temperature and gas temperature profile through the convection pass
- Secondary superheater surface effectiveness factor

The performance of the components in the rear pass of the unit could not be analyzed in detail because of insufficient test measurements (gas flow through each of the three lanes was not measured). However, the heat absorbed by the entire low temperature superheater could be calculated. On the other hand, the heat absorbed by the low temperature reheater could not be calculated because there was no outlet steam temperature measurement.

Thermal Performance Results

The results of the thermal performance calculations are summarized in Table 12-3. At full load (about 115 MW) the main impact of thermal performance was a shift in the heat absorption from the waterwalls to the convective pass sections as was the case with the original reburn system. Reburning decreased waterwall heat absorption by approximately 2.1% while the convective section heat absorption increased by approximately 2.1%. The decrease in waterwall heat absorption is due to the decrease in cyclone loading. The increase in convective pass absorption is attributed to the higher furnace outlet gas temperatures (calculated to be 42°F at the furnace outlet plane) and increased flue gas weight with reburning.

Comparing the full load tests 106A and 106B it can be seen that the firing of 18% natural gas resulted in a substantial improvement in boiler operation. Steam temperature at the superheater outlet increased from 952.6°F to 1000.4°F while at the reheater outlet the steam temperature increased from 925.0°F to 981.8°F; steam temperature design targets in both cases being 1000°F. Boiler efficiency, however, dropped 0.74% due to the higher hydrogen content of the natural gas which results in a higher moisture from fuel loss.

At 79% load the change in thermal performance created by the reburn system was less noticeable and in the opposite direction. Contrary to the full load tests, waterwall heat absorption increased 0.3% while the convection pass heat absorption decreased by 0.7%. The combination of the lower gas weight, lower furnace outlet gas temperature and higher steam flow resulted in the final steam temperatures going down instead of up with reburn. The reason for the increase in waterwall heat absorption is not clear but may be due to an overall cleaner furnace or more rapid fuel burnout. The 79% load tests were run at much higher excess air than the full load tests. This could be why the same trends were not observed at both loads.

Boiler efficiency was lower at part load with the reburn system in operation as was the case at full load. Boiler efficiency decreased by 0.59% compared to 0.74% at full load. At full load the effectiveness of the secondary superheater was about 6% less with reburn. At 79% load the effectiveness was up 3%. These changes are probably related to changes in overall furnace cleanliness.

As discussed above, boiler efficiency was decreased during reburn operation because the higher hydrogen content of the natural gas resulted in higher loss from moisture in the fuel. However, boiler performance was improved at full load with natural gas due to more nearly achieving design superheat and reheat steam temperatures. At reduced load, the boiler performance was about the same for the baseline and reburn cases.

Table 12-3
Summary of Results

TEST NO.:	106A	106B	109E	109A
TYPE OF TEST	BASELINE	18% REBURN	BASELINE	18% REBURN
GROSS MW	114.4	115.9	90.3	91.0
HEAT FROM COAL %	100	82	100	82
HEAT FROM GAS%	0	18	0	18
EXCESS AIR %	9.2	11.9	24.5	21.4
STEAM TEMP. SHO-°F	952.6	1000.4	966.8	957.4
STEAM TEMP. RHO-°F	925.0	981.8	924.2	920.0
MAIN STM FLOW LBS/HR	901300	877400	676900	684500
REHEAT STM FLOW LBS/HR	799453	778254	600410	607152
SH SPRAY FLOW LBS/HR	0	2000	0	0
RH SPRAY FLOW LBS/HR	0	0	0	0
GAS RECIRC FLOW LBS/HR	0	0	0	0
GAS FLOW THRU CONV PASS LBS/HR	962300	992600	841000	833100
AIR FLOW THRU AIR HTR LBS/HR	879500	914300	776700	771800
COMPONENT HEAT ABSORPTIONS - MBTU/HR				
PRIMARY SUPERHEATER	104.5	120.5	79.7	78.2
SECONDARY SUPERHEATER	161.3	163.1	124.5	124.5
REHEATER	121.4	126.4	93.4	95.4
WATERWALLS	627.5	608.2	488.6	494.1
TOTAL	1014.7	1018.2	786.2	792.2
HEAT LOSSES - %				
DRY GAS LOSS	2.32	2.41	2.26	2.24
MOIST FROM FUEL LOSS	4.32	5.29	4.28	5.17
MOIST FROM AIR LOSS	0.06	0.06	0.05	0.05
RADIATION LOSS	0.23	0.23	0.30	0.30
ASH PIT LOSS	0.52	0.43	0.52	0.44
CARBON LOSS	1.39	1.16	1.39	1.19
TOTAL	8.84	9.58	8.80	9.39
BOILER EFFICIENCY %	91.16	90.42	91.20	90.61
BTU FIRED MBTU/HR	1113.1	1123.6	862.2	874.3
LBS FUEL FIRED	95990	89359	74353	70056
SURFACE EFFECTIVENESS FACTORS				
SECONDARY SUPERHEATER	0.975	0.912	1.045	1.074
GAS TEMPERATURES - °F				
SECONDARY FURN. OUTLET	2078	2120	1913	1892
REHEATER INLET	1555	1615	1442	1417
REAR CAV. OUTLET	1283	1348	1195	1114
PRIMARY SH & LTRH INLET	1269	1334	1183	1104
AIR HEATER INLET	658	674	644	626
AIR HEATER OUTLET	246	249	236	230

Evaluation of the Modified Reburn System Design and Performance

Reviews of parametric test results and discussions between project sponsors, contractors, and consultants were held during December 1991 and early January 1992 to identify the reasons why the modified reburn system gave lower NO_x reduction than the original system and to develop recommendations for improving NO_x reduction. These discussions and the recommendations are summarized in this subsection.

The observation of luminosity in the reburn zone during testing of the modified system was an important input in identifying the cause of the lower NO_x reduction for the modified system. Another observation was the reduced thickness of the slag layer and resulting increased heat absorption in the waterwalls although the elimination of FGR may have compensated all or in part for this effect. The key reasons for the lower NO_x reduction were thought to be:

- Pyrolysis of the natural gas during operation of the modified system, evidenced by the greater luminosity rather than the desired chemical reaction which is hydroxylation. Pyrolysis converts natural gas into carbon (soot formation) and hydrogen rather than the more reactive intermediate chemical compounds such as CH, CH_2, CHO, and OH which are generated during hydroxylation and which are essential for the reburn process.
- Reduced temperatures in the reburn zone which slowed the rate of the NO_x-destroying reburn chemical reactions. Possible lower temperatures in the reburn zone may have resulted from a combination of these factors:
  - Greater heat transfer to the waterwalls in the reburn zone due to the reduction of the slag layer thickness on the back wall.
  - Greater heat transfer to the waterwalls in the reburn zone due to higher flame emissivity of the more luminous gases.
  - Offsetting these effects to some extent but not sufficiently to counteract them completely was the elimination of the recirculated flue gas and the attendant thermal dilution.

It was believed that CO_2, H_2O, and the O_2 in the recirculated flue gas used in the original design caused hydroxylation of methane to occur rather than straight pyrolysis. A question which remained unanswered, however, was how much flue gas is needed to prevent pyrolysis. The quantity may be very small because the performance of the original system was essentially unchanged when the FGR was reduced from 16% to 3%. Mixing effectiveness with the modified reburn system did not seem to be a factor, at least not at Niles No. 1. This conclusion was based on the fact that NO_x removal performance was essentially unchanged when the natural gas tips were removed or when other changes were made to the natural gas injector configurations. One final observation about the importance of reburn zone temperature was provided by the fact that the reduction in NO_x was significantly lower at part load for the modified system than for the original system. Under part load reburn operation with the modified system the reburn zone was especially cool because of the combined effects of the reduced slag layer thickness, the greater

gas luminosity, and the inherently cooler temperatures during part load operation. It should also be noted that NO_x reduction decreases as the inlet NO_x concentration decreases.
The following recommendations were made for improving NO_x reduction:

- Premix steam and/or water with the natural gas before injection into the reburn zone.
- Premix a small amount of flue gas with the natural gas before injection into the reburn zone.

Project Planning

A meeting of project sponsors, contractors, and consultants was held on January 15, 1992. At this meeting the modified system parametric test results were reviewed, reasons for the lower NO_x were discussed, recommendations for improving NO_x reduction were presented, comments from Ohio Edison regarding operation of the modified reburn system were presented, boiler tube wastage measurements were reviewed, recommendations for effective continuous NO_x measurements were presented, the project budget status was discussed, and project plans were formulated. Because of time and budgetary constraints, a decision was made to proceed with long-term load dispatch testing using the modified reburn system and to postpone parametric testing to improve NO_x emissions reduction until completion of the long-term tests. The long-term tests are discussed in Section 13.

Water Injection

Adding water to the reburn zone was determined to be the most economic and technically feasible method for improving the performance of the modified reburn system. Design and fabrication of combined natural gas and water injectors proceeded during the long-term dispatch testing. However, an opportunity for a brief evaluation of water introduction to the reburn zone was provided in January 1992 during the initial start-up of the long-term testing. This occurred when water leaks developed in the water-cooled guide-tubes of two of the five natural gas injectors. NO_x and CO emissions data for the brief water-leak and the more detailed, controlled water injection tests conducted in July 1992 are listed in Table 12-1. Data for the full-load parametric tests of the original and modified reburn systems are also listed in Table 12-1. The water injection tests are discussed in further detail in the following paragraphs.

Parametric Testing with Water Leaks through Guide Tubes

During the initiation of long-term load dispatch testing, water leaks were detected on reburn Nozzle A and Nozzle E water-cooled guide pipes. Nozzle A was on the far left (west) side of the furnace, and Nozzle E was on the far right (east) side of the furnace. These leaks added water into the reburn zone in an uncontrolled manner since there was no measurement of the flow rates and no positive indication of where on the guide pipes the leaks were located. However, since the NO_x monitoring indicated a reduction in NO_x, NO_x and CO emissions data were recorded. NO_x emissions comparisons at full load are shown in Figure 12-6. With natural gas injected only through Nozzles B, C, and D (the center three nozzles) the NO_x emissions were reduced by 50 to 75 ppm to the level comparable to NO_x emissions measured with the original reburn system.

With natural gas injected through all five nozzles, there was further reduction in NO_x--a reduction of approximately 100 ppm compared to previous data for the modified system.

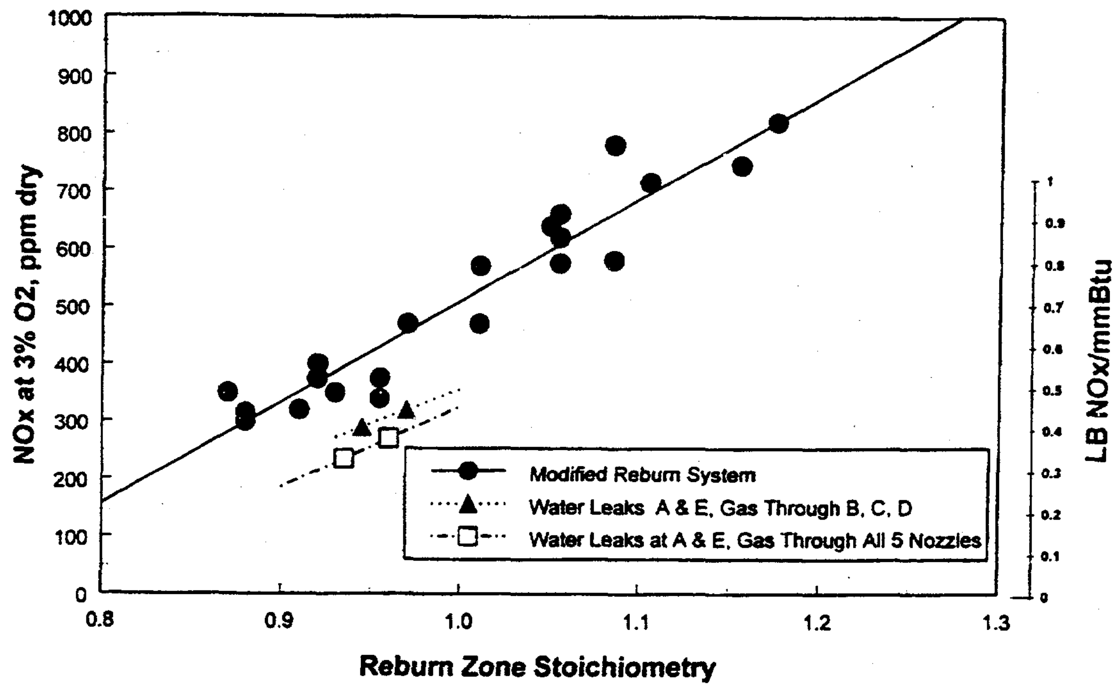


Figure 12-6
NO_x Emissions for the Modified Reburn System and Tests with Water Leaks

Parametric Testing with Water Injection

As discussed above, the parametric reburn tests of the modified reburn system with water injection were conducted in July 1992, after completion of the long-term dispatch tests to be discussed in Section 13.

Figure 12-7 is a sketch of a modified system natural gas injector with a water injection atomizer added. The natural gas tip was removed. Water entered through a pipe in the center of the natural gas passage and was injected through a pressure atomizing spray nozzle. In a modification of the design, the pressure atomizing water spray nozzle was removed and the water entered the natural gas passage from the end of the water pipe. A third water injector, called the "doughnut injector", was designed to simulate the leak in the guide tube. For this design, water flowed through a separate annulus inside the water cooling passage and entered the natural gas stream flowing radially inward through holes at the tip of the water annulus. Doughnut injectors were installed in nozzle locations A and B for the final series of water injection tests.

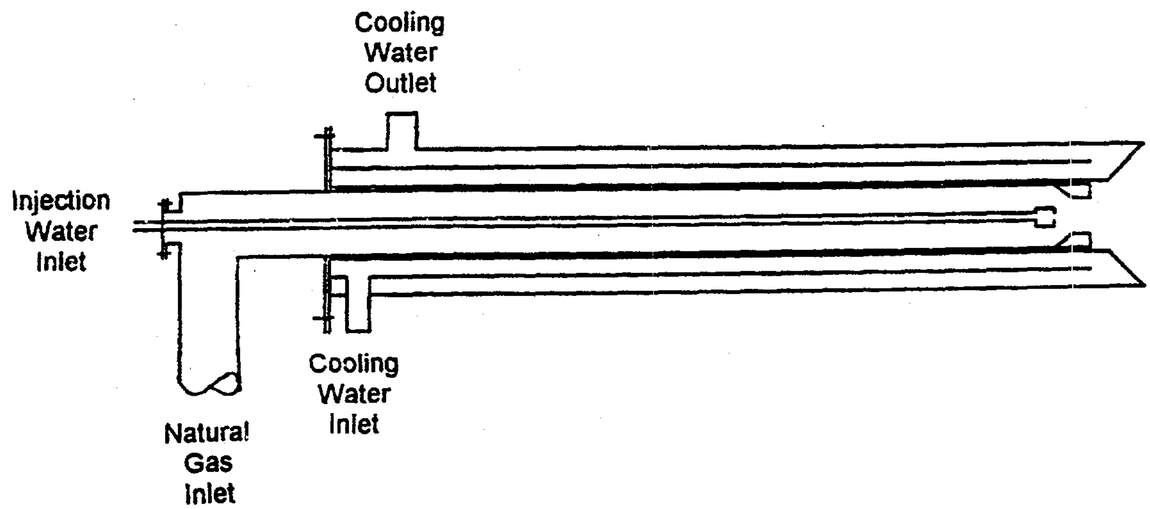


Figure 12-7
Water Injection for the Modified System

A tabulation of water injector configurations and data for the water injection tests is given in the file H2O.XLS on Diskette 1. NO_x emissions for the full load parametric testing of the modified system both without and with water injection are shown in Figure 12-8. Some of the NO_x levels achieved during the water leak tests (Figure 12-8) are lower than what was achievable during the controlled water injection testing. In an effort to explain the differences between NO_x levels during water leak tests vs. controlled water injection testing the oxygen levels for each cyclone were reviewed. It was found that two of the four cyclones were operating at very low O_2 during the water leak tests; this is verified by the high CO levels as shown in Table 12-1 (Test No. 110A, 111C, 111D, and 111E) which ranged from 508 to 1771. It can be reasonably speculated that the NO_x levels for those cyclones with low O_2 would have been lower than had the cyclones all been operating at the target 2.5 to 3.0 percent O_2. It can be further speculated that the inlet NO_x to the reburn zone would not have been as high in the water leak tests and that might be the real explanation for why the water leak tests gave lower NO_x which could not be repeated during the controlled water injection testing.

Also shown in Figure 12-8 are data for the long-term tests conducted in June 1992, reburn tests with water off conducted in July 1992, and the water leak tests discussed above. The data show an improvement in NO_x removal for the water injection tests relative to the parametric tests conducted in October and November 1991. However, the water injection tests gave NO_x removal performance a bit lower than the performance for the long-term tests conducted in June 1992 and the three baseline tests with gas on and water off conducted in July 1992. The small drop-off in NO_x removal during the water injection tests may have been due to cooling of the gases and resulting slowing of the reburn chemical kinetics. The excellent NO_x removal efficiency achieved during the June 1992 long-term tests is discussed further in Section 13.

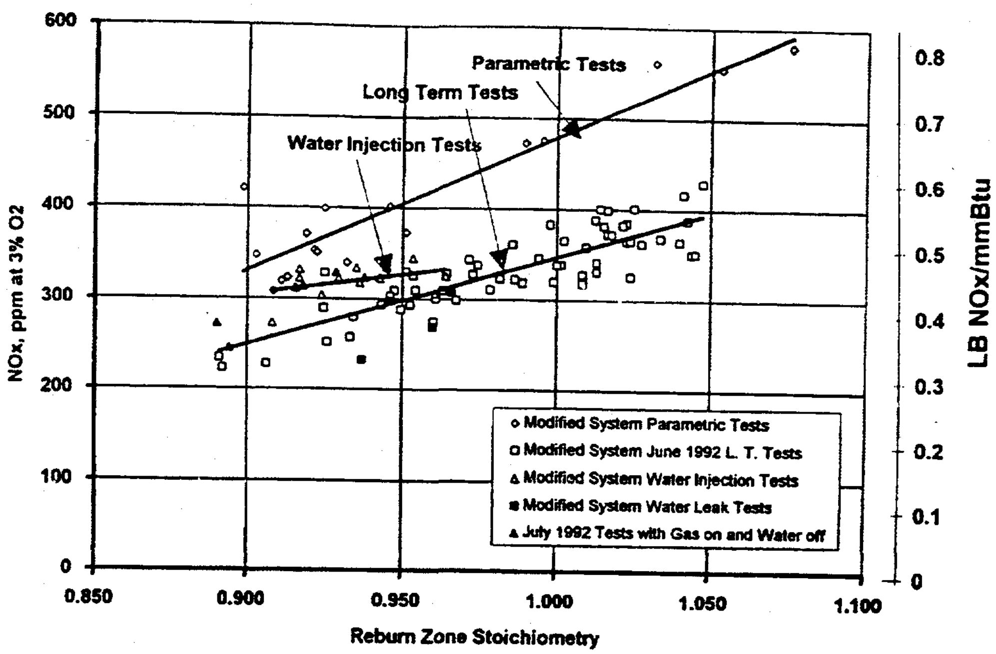


Figure 12-8
Modified Reburn System NO_x Emissions at Full Load for Parametric Tests, Long-Term Tests in June 1992 and Parametric Tests with Water Injection

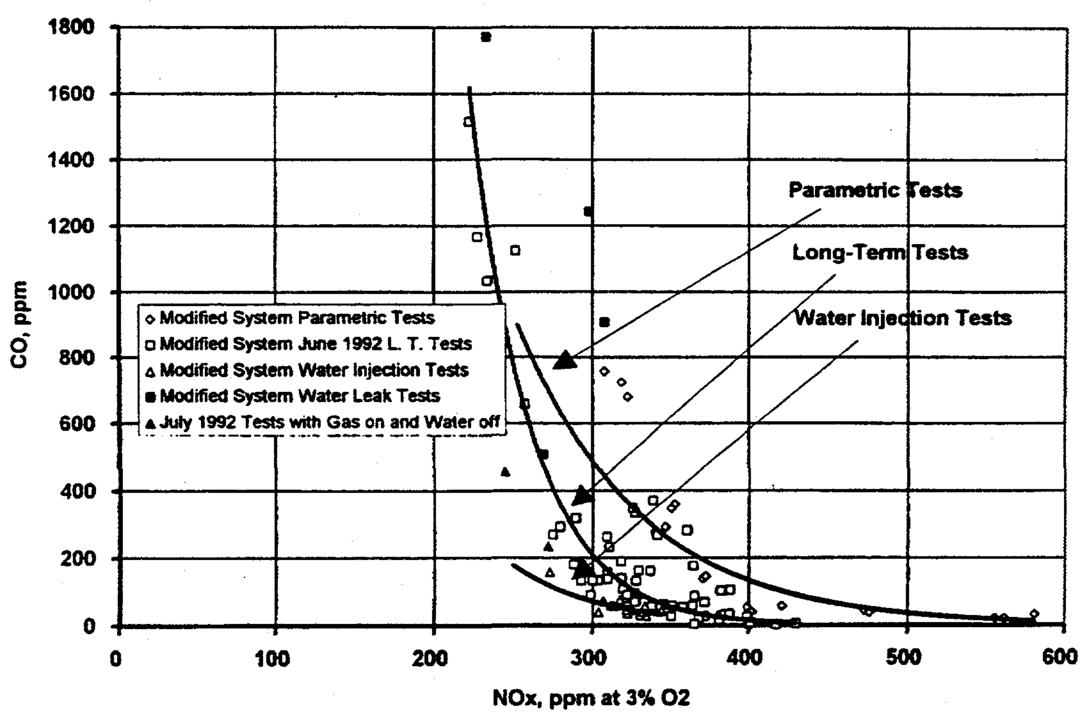


Figure 12-9
NO_x-CO Emissions Comparison for the Modified System Without and With Water Injection

Figure 12-9 compares the CO emission data for the water injection reburn tests and the uncontrolled water leak tests to the CO emission for the modified reburn system without water injection. All of the tests showed an exponential rise in CO as reburn zone stoichiometry, and corresponding NO_x emissions, were decreased. However, water injection provided a substantial reduction in CO emission relative to reburn operation without water injection. Inspection of the file H2O.XLS provides some interesting insight concerning the effects of water injection on the reburn process. A wide range of water flows and a great variety of water injector configurations were tested including water injection through open pipes with the water atomizers removed. The CO concentration was nearly unchanged for this range of water flows and injector configurations. This suggests that the CO reduction was a chemical phenomenon rather than a mixing - limited phenomenon and that only a small amount of water may be needed to reduce CO to low levels. Inspection of Figure 12-8 also shows that the water injection tests were conducted over a small range of reburn zone stoichiometries. The water injection tests were conducted at the very end to the test program under tight time constraints which did not permit testing over an adequate range of water flows or reburn zone stoichiometries. It is interesting to speculate on what the results may have been if testing had been conducted at reduced total water flow rates, such as 2 or 3 gallons per minute, and lower reburn zone stoichiometry. If reduced water flows had given NO_x measurements similar to the long-term tests and CO emission similar to the other water injection tests, the operations would simultaneously have the minimum emissions of both NO_x and CO. Extrapolating the minimum emissions lines in Figures 12-8 and 12-9 would give estimates of NO_x and CO emissions of NO_x = 249 ppm at 3% O_2 and CO = 180 ppm at a reburn zone stoichiometry of 0.90 and NO_x = 230 ppm at 3% O_2 and CO = 259 ppm at a reburn zone stoichiometry of 0.88. The corresponding NO_x reductions, relative to a baseline NO_x of 670 ppm are 62.8% and 65.7% at reburn zone stoichiometries of 0.90 and 0.88, respectively.

Conclusions

Testing of the modified reburn system with water injection led to the following conclusions:

1. The NO_x removal performance for the modified reburn system with water injection was better than the performance achieved during the parametric testing of the modified reburn system. However, the performance with water injection was no better, and perhaps a bit poorer, than the NO_x removal performance achieved during long-term reburn testing in June 1992 and during reburn tests with gas on and water off conducted in July 1992.
2. For all reburn systems tested, CO emission increased exponentially as reburn zone stoichiometry and corresponding NO_x emissions were reduced.
3. The modified system with water injection provided a reduction in CO emissions compared to all tests with the modified system without water injection.
4. The effectiveness of water for reducing CO emission was independent of the quantity of water used over the full range of water flows tested.

5. The method of mixing water within the reburn zone appeared to be of minimal importance, at least at Niles Unit No. 1, because NO_x and CO emissions were about the same for a wide range of water injection configurations.
6. Controlled water injection during natural gas reburning has the potential for concurrently providing minimum emissions of both NO_x and CO.

13

LONG-TERM LOAD DISPATCH TESTING

Purpose of Long-Term Testing

Long-term testing was initiated after parametric testing had established the effect of major reburn system variables on system performance. Long-term testing was conducted to:

- document the reliability of the system,
- compare system performance under fluctuating boiler load and excess oxygen operating conditions as compared to the closely controlled operating conditions present under parametric testing,
- evaluate the potential for changes in tube wastage caused by the reducing atmosphere created in the reburn zone,
- document the effects of reburning on boiler equipment, operations and performance under long-term commercial power-plant operation.

Data was logged for 1196 hours of operation between March 2, 1992 to June 19, 1992. This section discusses long-term operation of the reburn system, discusses the NO_x emission reduction performance of the system in long-term service, including a comparison with performance measured during parametric testing, discusses the commercial potential of gas reburn for NO_x emissions control, and presents a utility perspective of the reburn process for retrofit of cyclone-fired furnaces based on 3 1/2 month's experience at Niles Unit No. 1. This information expands on information given by Brown and Borio (1992) and Borio et al. (1993).

Reburn System Operation

The reburn system was designed to operate at the design reburn fuel heat input of approximately 16% at loads greater than 80 MW. Below 80 MW, the reburn fuel heat input was to be proportionally ramped down to 0% at 65 MW. The reburn fuel flow was restricted in this manner to maintain sufficiently high temperatures in the primary combustion zone to keep the slag molten and permit tapping without undue difficulty. The reduction in reburn fuel flow led to decreased NO_x reduction during part-load operation. Moreover, during long-term testing, the unit was never operated in a reburn mode below 80 MW, the primary reason being operator judgment relative to slag tapping concerns.

Based on parametric testing conducted immediately after the modified reburn system was installed, it was decided to operate the reburn zone at a target stoichiometry of 0.94. This stoichiometry was higher than that used as the target during parametric testing; reasons for the higher stoichiometry will be discussed later.

Niles Unit No. 1 operated 2439 hours during the time period between March 2, 1992 and June 19, 1992. Data acquisition was in operation for 1196 hours during this time period. Data acquisition times included times when the reburn system of operated at design conditions (gas energy input 16% or greater fraction of total energy input), times of off-design reburn operation (gas input 3% to 16% of total energy input), and times when baseline data were obtained by operating the data acquisition system with the reburn system not in operation. The distribution of data acquisition times by load range and reburn system operating range is listed in Table 13-1. As noted above, the reburn system was never employed when the load dropped below 80 MW. Additionally there were periods when reburn fuel was not injected at loads above 80 MW because of cooling water leaks in the reburn fuel guide pipes, a furnace casing leak, and malfunctions of the natural gas control valve and instrument air compressor. Corrective actions for these mechanical malfunctions, which can be considered typical for the first commercial installation of a gas reburn system, are available.

Table 13-1
Distribution of Load and Reburn Conditions during Long-Term Data Acquisition

Load Range (MW gross)	Hours of Operation			
	Design Reburn Operation (16+ % gas)	Off-Design Reburn Operation (0 - 16% gas)	Baseline Operation (0% gas)	Total Data Acquisition Hours
110+	154	16	30	200
110 - 100	213	63	57	333
100 - 90	187	150	129	466
90 - 80	9	34	65	108
below 80 MW	0	0	89	89
Total	**563**	**263**	**370**	**1196**

Long-Term NO_x and CO Emissions

Long-term NO_x emissions data for tests between March 2 and April 29, 1992 are presented for four boiler load ranges in Figures 13-1, 13-2, 13-3, and 13-4 where NO_x is plotted against Reburn Zone Stoichiometry (RZS). Each point is the arithmetic average of twelve measurements logged at five minute intervals. One-hour average test data for full-load operation with reburn fuel fraction of 16% or greater are also presented in Table 13-2. A summary of reburn performance for all load ranges and all gas fractions is contained in Diskette 1 under the file name LTDATA.XLS. NO_x emissions during the March through April time frame averaged about 370 ppm at full boiler load rather than the original system parametric test values in the 300 to

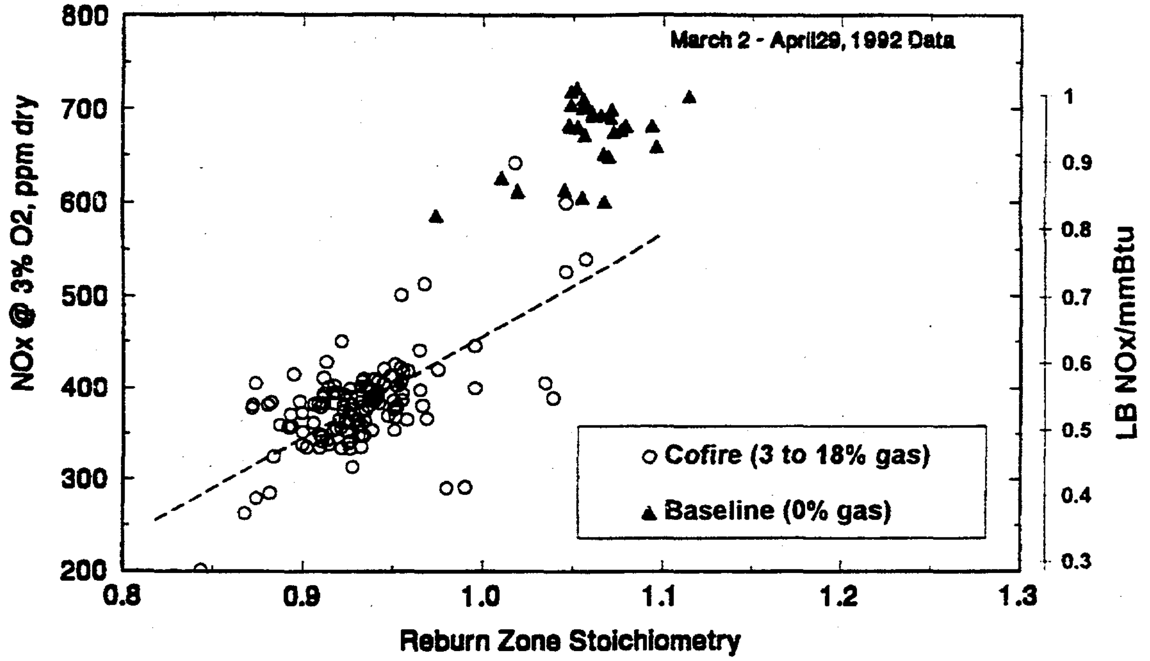


Figure 13-1
Variation of NO_x Emissions with RZS at 110+ MWe

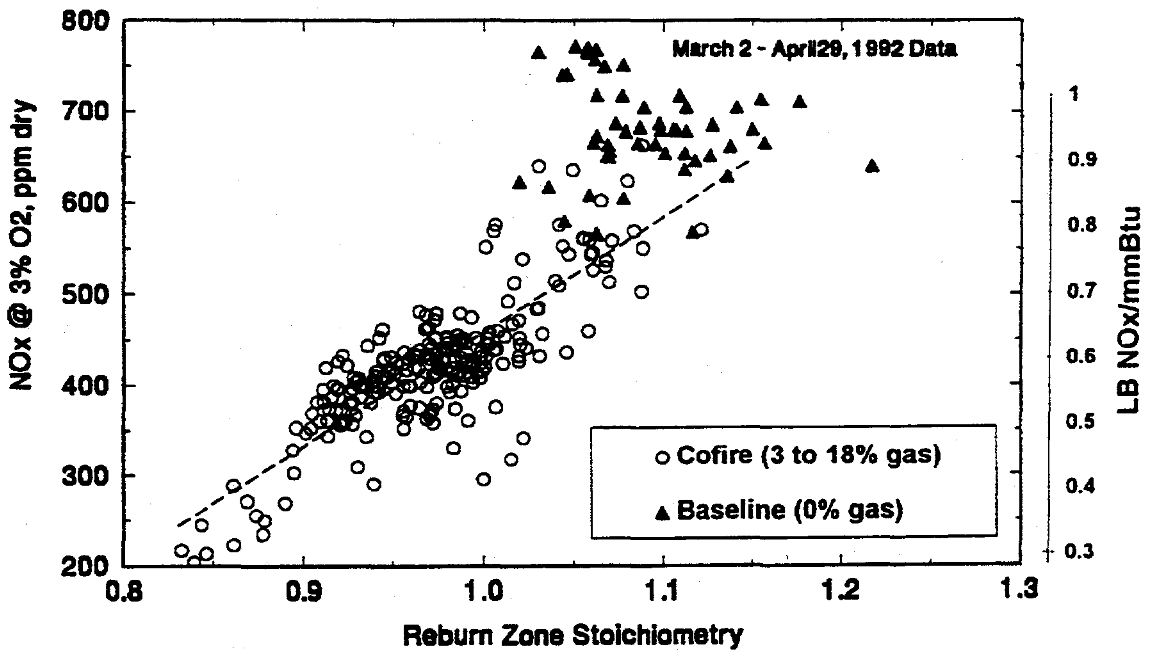


Figure 13-2
Variation of NO_x Emissions with RZS at 100 - 110 MWe

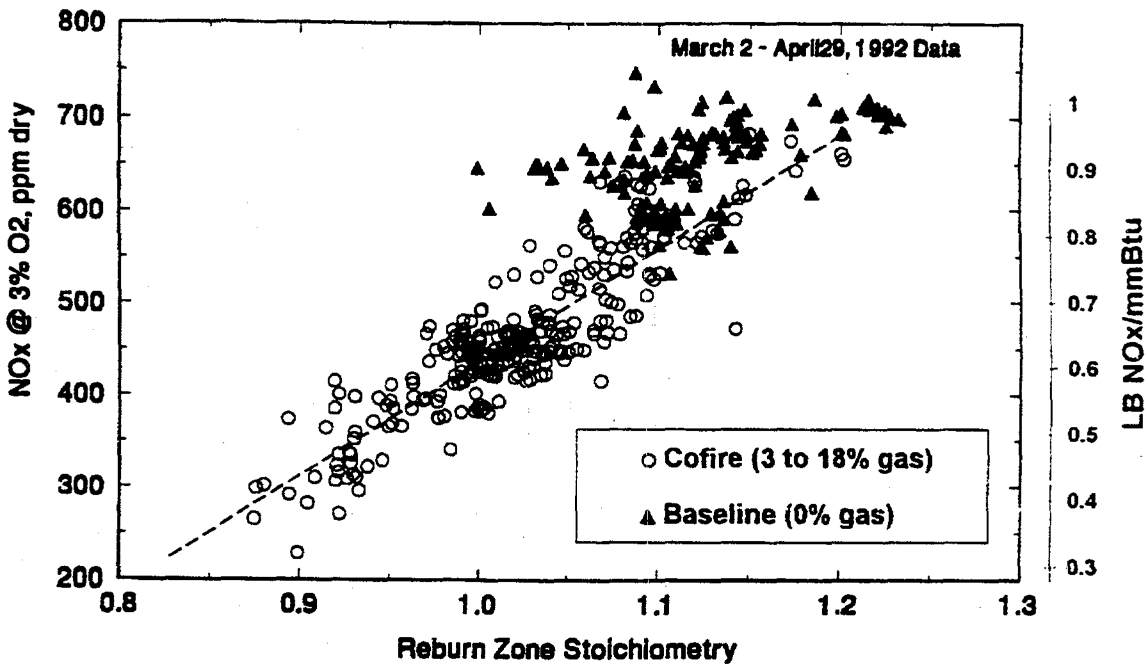


Figure 13-3
Variation of NO_x Emissions with RZS at 90 - 100 MWe

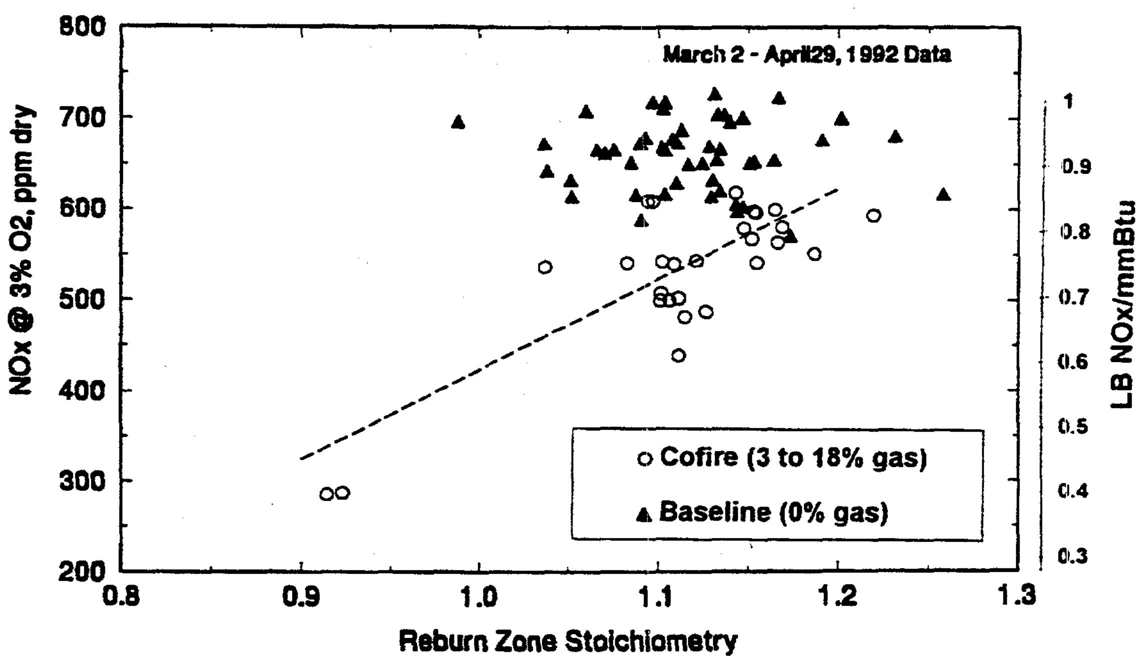


Figure 13-4
Variation of NO_x Emissions with RZS at 80 - 90 MWe

Table 13-2
Full-Load Long-Term Emissions Data for Reburn System Operation with 16% or Greater Natural Gas Reburn Fuel

Long Term Tests March 2-April 29, 1992 with							Long Term Tests June 12-June 19, 1992 with						
Load >= 110 MW and Gas >= 16%							Load >= 90 MW and Gas >= 16%						
		Gross Load	ESP in NOx	ESP in CO	Reburn Zone	NOx Red. (672 Base)			Gross Load	ESP in NOx	ESP in CO	Reburn Zone	NOx Red. (670 Base)
Date	Hour	(MW)	(ppm@3%	ppm	Stoich.	(%)	Date	Hour	(MW)	(ppm@3%	ppm	Stoich.	(%)
304	19	115.1	291	468.0	0.9802	56.78	613	1	94	325.6	79.4	0.9536	51.41
304	20	114.2	292	437.5	0.9905	56.65	613	10	111.5	309.4	155.8	0.9474	53.83
316	7	110.7	391	66.7	0.9118	41.85	613	11	95.4	364.9	176.1	1.0227	45.54
316	8	113.5	385	24.5	0.9323	42.76	613	12	108.2	222.6	1514.3	0.8920	66.78
318	9	113.4	390	266.4	0.9417	42.04	613	13	110.1	234.1	1032.8	0.8909	65.06
318	12	111.8	421	147.9	0.9454	37.43	613	14	96.2	275	269.2	0.9602	58.96
318	13	114.8	409	148.4	0.9398	39.12	613	15	103.9	328	131.4	0.9644	51.05
318	14	115.3	408	275.6	0.9423	39.31	613	16	113.6	399.2	23.7	1.0167	40.42
318	15	113.5	426	113.9	0.9514	36.66	613	17	103.6	372.5	25	1.0167	44.41
318	16	114.8	405	248.8	0.9456	39.75	613	18	107.5	382.7	26.2	0.9979	42.89
318	17	113.6	406	198.8	0.9548	39.57	613	19	98.1	381.7	14.9	1.0155	43.04
318	19	114.6	396	301.3	0.9375	41.10	613	20	92.9	368.5	20.1	1.0337	45.01
318	20	113.3	397	232.2	0.9417	41.03	613	21	111.3	360.7	281.4	0.9856	46.17
318	21	113.0	387	363.8	0.9553	42.50	613	22	113.7	303.5	132.9	0.9462	54.71
319	8	114.3	386	212.0	0.9508	42.57	614	12	102.4	318.9	139.3	0.9889	52.41
319	9	113.5	405	67.4	0.9451	39.72	614	13	98.3	345.8	61.1	0.9942	48.39
319	10	113.1	402	76.1	0.9527	40.17	615	10	115.7	279.5	292	0.9343	58.29
319	13	112.7	394	80.2	0.9555	41.41	615	11	115.5	293	131.1	0.9434	56.27
319	21	111.6	389	109.7	0.9390	42.14	615	12	116.6	384.6	30.3	1.0227	42.60
320	19	115.3	410	206.2	0.9341	38.97	615	13	116.9	400.1	2.3	1.0143	40.29
320	20	110.6	417	191.3	0.9561	37.96	615	14	115.5	343.7	56.2	0.9718	48.71
320	22	111.3	409	86.1	0.9554	39.14	615	15	113.7	401.3	6.2	1.0251	40.11
321	19	112.5	412	337.7	0.9117	38.77	615	16	103.2	417.2	1.3	1.0412	37.74
321	20	111.4	401	216.6	0.9325	40.30	615	17	97.6	429.6	-3.9	1.0475	35.89
322	9	113.7	393	206.8	0.9229	41.59	615	20	101.7	387.9	32.2	1.0425	42.11
323	13	112.0	415	404.2	0.8948	38.23	615	21	113.2	365.6	86.8	1.0025	45.44
323	21	111.1	403	268.4	0.9356	40.14	615	22	115.8	365.5	2.1	1.0239	45.45
324	17	114.2	371	562.0	0.8932	44.80	616	9	100.2	257.5	657.8	0.9332	61.57
324	18	115.3	358	730.7	0.8920	46.70	616	10	101.5	309.8	136.2	0.9544	53.77
324	19	115.2	359	396.4	0.8872	46.55	616	11	106.3	328.1	73	0.9249	51.04
324	20	114.4	357	466.2	0.8924	46.94	616	6	100.1	362.3	50.4	1.0276	45.93
324	21	114.8	352	629.1	0.8998	47.67	616	7	101.2	372.1	67.9	1.0180	44.47
324	22	114.3	349	706.0	0.9094	48.07	616	8	100.4	358.2	53.1	1.0096	46.54
325	2	114.6	356	468.0	0.9212	47.00	616	9	106.4	382.5	102.4	1.0215	42.92
325	3	115.2	374	141.4	0.9226	44.34	616	10	100.1	327.3	332.8	0.9730	51.15
325	4	113.7	376	141.8	0.9354	44.03	616	11	94.9	388.2	104.1	1.0126	42.07
325	6	113.2	364	380.5	0.9348	45.88	616	19	95	325.9	346.4	1.0240	51.36
325	14	111.0	399	55.0	0.9263	40.60	616	20	106.4	341.8	267.8	1.0130	48.99
325	15	112.2	391	86.5	0.9389	41.81	616	21	105.1	310.9	231.5	0.9785	53.60
325	16	112.9	387	95.7	0.9375	42.39	616	22	109.3	318.4	189.2	1.0083	52.48
325	17	111.4	386	349.7	0.9400	42.63	616	23	114.8	309.2	262.5	0.9633	53.86
325	18	114.8	380	222.5	0.9101	43.51	617	0	115.8	293.2	178.8	0.9526	56.24
325	19	110.0	392	156.2	0.9310	41.75	617	1	115.7	300.4	132.6	0.9609	55.17
325	21	112.2	395	72.9	0.9187	41.29	617	2	114.5	322.8	54.4	0.9817	51.83
326	8	111.2	408	197.2	0.9333	39.39	617	3	101.6	351	25.4	1.0437	47.62
326	10	111.8	403	323.3	0.9174	40.10	617	4	108.3	319.9	107.7	0.9991	52.26
326	13	111.2	382	130.2	0.9226	43.20	617	5	115.2	322.2	89.2	0.9865	51.92
327	8	111.9	395	71.8	0.9120	41.31	617	6	107.7	338.8	369.5	1.0015	49.44
327	13	112.2	429	106.0	0.9130	36.25	617	7	99.7	327.5	69.4	1.0083	51.12
328	8	111.6	405	591.3	0.8736	39.75	617	8	98.8	364.4	58	1.0399	45.62
328	9	115.6	382	1023.0	0.8721	43.25	617	9	112.9	337.4	160.7	0.9746	49.65
328	10	115.5	378	1063.9	0.8716	43.80	617	10	114.7	288.2	179.9	0.9497	56.99
328	11	110.3	384	586.1	0.8823	42.89	617	11	112.2	299	88.7	0.9675	55.38
328	12	112.2	401	208.2	0.9142	40.31	619	1	99.5	338.4	54.8	1.0000	49.50
329	9	110.8	390	862.1	0.9267	42.01	619	5	95.1	351.5	58	1.0450	47.54
330	2	110.3	413	176.0	0.9490	38.53	619	6	99.2	331	28.6	1.0130	50.60
330	6	112.3	383	416.3	0.9175	43.00	619	7	100.5	251.9	1124.6	0.9259	62.41
330	7	111.4	373	437.4	0.9259	44.50	619	8	102.6	227.8	1167	0.9064	66.00
330	8	113.5	377	149.8	0.9262	43.91	619	9	107.4	289.5	316.5	0.9248	56.80
330	9	111.9	381	80.1	0.9275	43.29	619	10	111	329.6	162.3	0.9515	50.81
330	16	110.4	399	227.8	0.9377	40.66							
331	0	111.3	383	433.8	0.9114	42.99							
331	1	113.2	385	613.1	0.8982	42.70							
331	2	111.5	383	262.5	0.9065	43.10							

Table 13-2 (Continued)
Full-Load Long-Term Emissions Data for Reburn System Operation with 16% or Greater Natural Gas Reburn Fuel

331	3	111.3	383	286.1	0.9088	43.08					
331	4	111.4	395	339.3	0.9166	41.29					
331	21	110.4	373	229.1	0.8997	44.53					
401	6	113.4	382	701.7	0.8805	43.26					
401	16	110.5	358	59.2	0.8935	46.69					
405	20	115.1	362	80.1	0.9060	46.16					
406	6	110.8	398	39.9	0.9653	40.81					
406	21	111.7	446	20.2	0.9960	33.68					
406	20	114.1	441	21.8	0.9650	34.36					
406	21	111.7	446	20.2	0.9960	33.68					
407	16	111.3	126	2457.7	0.7777	81.30					
407	17	112.7	314	925.8	0.9278	53.37					
407	21	112.7	400	21.2	0.9957	40.50					
408	7	111.7	155	2458.4	0.8061	76.96					
408	18	110.8	201	1795.9	0.8432	70.11					
408	21	113.6	195	2523.5	0.8281	71.04					
411	10	112.4	354	46.1	0.9512	47.42					
411	11	110.5	354	54.4	0.9389	47.38					
413	22	115.1	280	1168.7	0.8740	58.44					
413	14	115.9	422	16.9	0.9546	37.24					
413	15	115.9	418	18.7	0.9587	37.77					
413	16	112.2	421	18.1	0.9754	37.46					
413	20	113.1	338	498.5	0.8995	49.68					
413	22	115.1	280	1168.7	0.8740	58.44					
413	23	115.4	335	91.4	0.9092	50.18					
414	8	115.5	366	84.3	0.9202	45.61					
414	0	116.3	363	36.5	0.9255	46.05					
414	1	112.9	384	20.9	0.9425	42.92					
414	2	112.8	380	23.0	0.9529	43.52					
414	3	111.0	380	19.6	0.9525	43.53					
414	4	110.6	380	28.8	0.9366	43.44					
414	5	113.9	383	26.4	0.9428	42.98					
414	6	113.8	390	20.1	0.9411	41.98					
414	8	115.5	366	84.3	0.9202	45.61					
414	11	110.7	365	119.6	0.9303	45.69					
414	12	112.7	369	33.5	0.9520	45.19					
414	13	111.1	365	42.8	0.9581	45.69					
414	15	115.8	342	240.9	0.9265	49.12					
414	16	114.0	347	202.6	0.9313	48.35					
414	17	114.4	334	307.6	0.9212	50.31					
414	18	115.5	334	176.6	0.9262	50.31					
414	19	115.5	347	63.1	0.9332	48.36					
414	20	115.8	348	59.1	0.9342	48.28					
414	21	115.4	360	45.4	0.9329	46.46					
414	22	114.8	340	85.6	0.9253	49.46					
415	8	115.0	342	160.7	0.9106	49.10					
415	6	110.0	351	228.0	0.9244	47.74					
415	7	111.4	355	173.6	0.9188	47.15					
415	8	115.0	342	160.7	0.9106	49.10					
415	9	115.8	352	94.3	0.9250	47.65					
415	10	115.6	370	36.6	0.9477	45.02					
415	11	113.4	377	23.4	0.9510	43.99					
415	12	112.1	381	25.7	0.9666	43.32					
415	15	116.2	394	28.2	0.9417	41.37					
415	16	115.3	391	23.1	0.9413	41.80					
415	17	115.2	375	36.1	0.9335	44.23					
415	18	114.5	364	41.1	0.9296	45.93					
415	19	113.5	360	73.8	0.9313	46.39					
415	20	115.9	363	56.0	0.9235	46.03					
415	21	115.1	367	30.1	0.9690	45.47					
415	22	114.7	336	79.1	0.9326	50.09					
415	23	115.1	339	109.5	0.9143	49.59					
416	0	115.6	335	161.0	0.9020	50.14					
423	9	114.6	325	872.9	0.8838	51.68					
423	10	111.4	263	2163.2	0.8674	60.91					
423	11	114.9	285	2271.7	0.8818	57.65					
423	12	115.4	343	853.2	0.9134	48.95					
423	13	115.8	354	605.5	0.9168	47.41					

330 ppm range principally because of the higher target RZS and other factors which may differentiate performance between the original and modified reburn systems as discussed in preceding sections. It is not uncommon for long-term NO_x emissions to run somewhat higher than values achieved during parametric testing (Wilson et al. (1991)). The relatively steady state conditions that exist during parametric testing minimize the fluctuations in air/fuel ratios that are bound to occur with load swings during normal boiler operation.

NO_x emissions during June 1992 reburn tests are presented in Figure 13-5 and Table 13-2. A reburn system data summary is provided in Diskette 1 in the file named JUNDATA.XLS. The June long-term data show significantly lower NO_x emissions than the NO_x emissions data measured between March 2 and April 29, 1992. The June 1992 long-term data demonstrate up to 55% NO_x removal with CO emissions less than 100 ppm with acceptable boiler operation and NO_x reduction of 66.8% at CO emission of 1514 ppm with acceptable boiler operation. This NO_x emissions reduction performance is superior to the NO_x reductions measured during parametric performance measurements for the original reburn system as shown in Figure 13-6. The long-term measurements verify that the performance achieved with the original reburn system can be duplicated with the modified reburn system. The most reasonable explanation for why the excellent NO_x emissions reduction were achieved in June 1992 is that the boiler operators became more experienced at maintaining target air/fuel ratios, in particular more uniform air/fuel ratios among the cyclones. Significantly, these results were obtained near the end of the long-term testing which provided increased operator familiarity and the ability to control key operational parameters within a tighter margin. It is believed that the June data are, indeed, representative of the performance that can be expected from the modified reburn system.

It was generally observed that the slope of the curves relating NO_x to RZS increased with increasing load. Figure 13-7 depicts the variation of NO_x with RZS for various load ranges. At high loads, 100-110 MWe for example, the curve for the March-April time period has a steeper slope than the 80-90 MWe load range curve. This higher percentage of NO_x reductions at higher loads is probably due to higher gas temperatures in the reburn zone at high loads and the higher inlet NO_x concentrations to the reburn zone. For comparison, the June data are also shown on this plot. As previously, noted the NO_x values measured in June were lower than the March-April values.

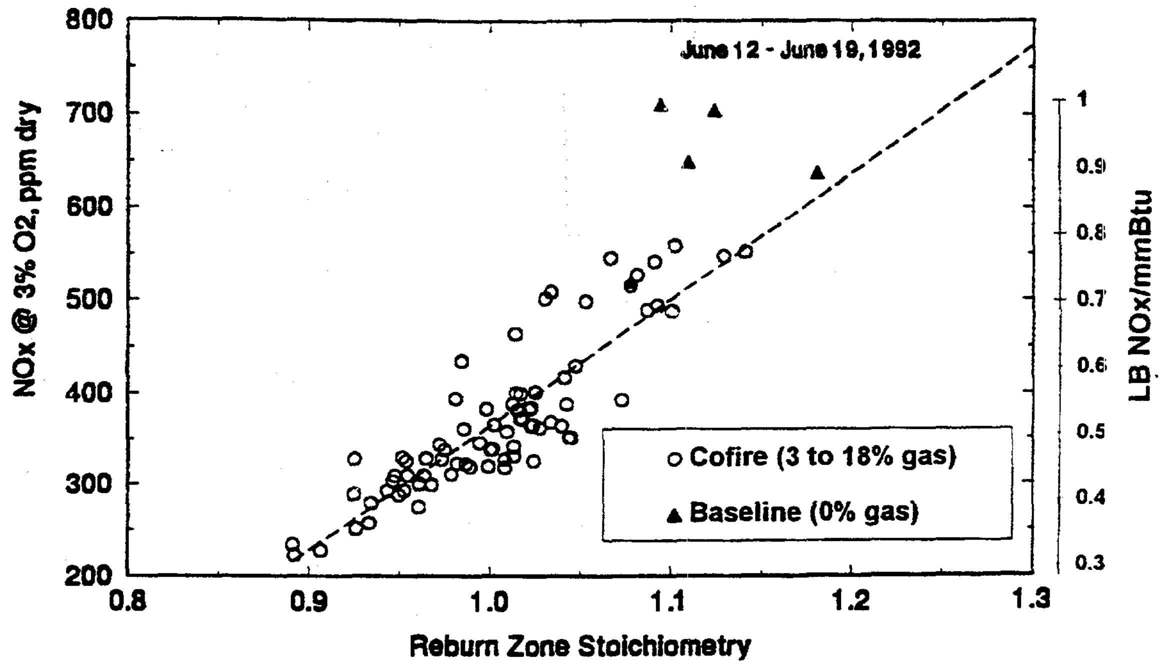


Figure 13-5
Variation of NO_x Emissions with RZS at 90-110+ MWe

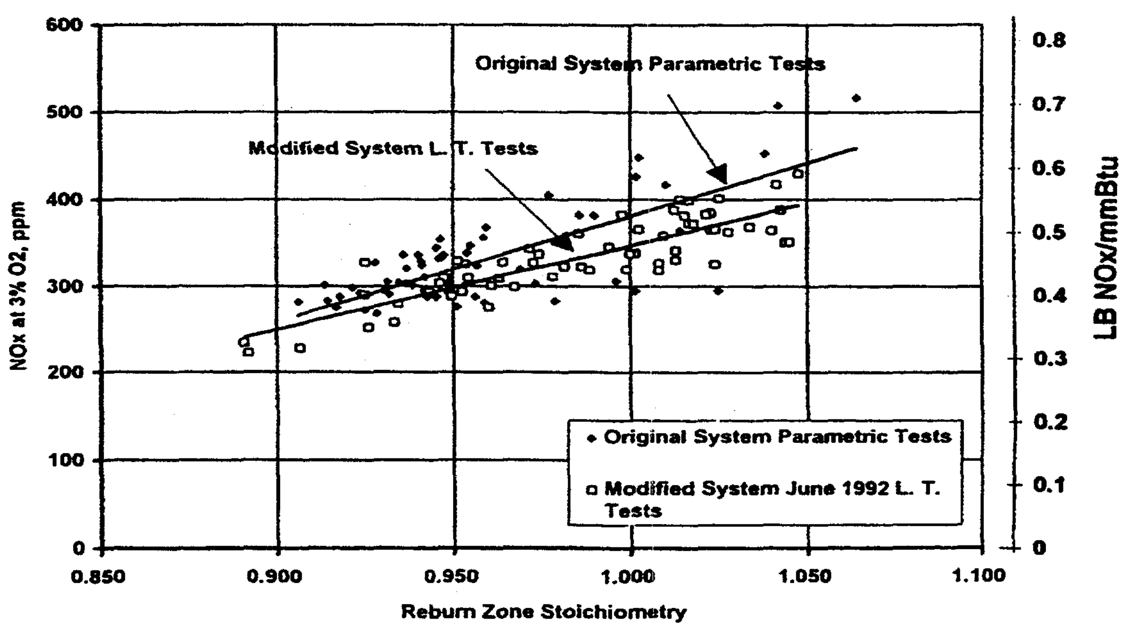


Figure 13-6
NO_x Emissions for the Original System Parametric Tests and the Modified System June 1992 Long-Term Tests

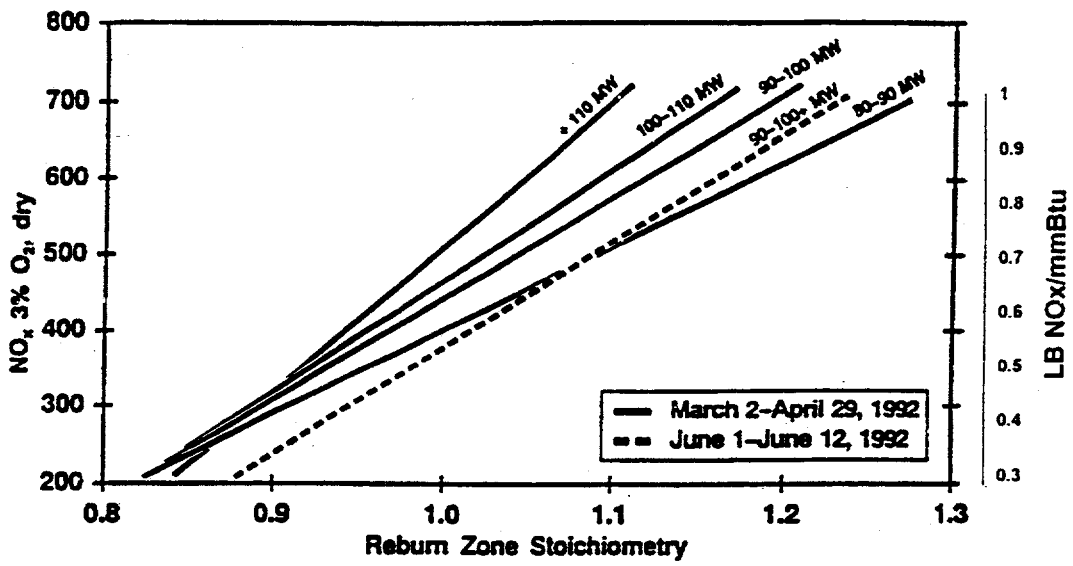


Figure 13-7
Comparison of NO_x Emissions at Different Loads

Difference Between Parametric and Long-Term Testing Conditions

Increased Target RZS

During parametric testing, the target RZS was 0.90. For long-term testing, it was raised to 0.94, primarily to maintain the CO level under 200 ppm (the baseline CO was about 35 ppm.) The variation of CO emissions with RZS is shown in Figure 13-8. It is apparent that CO increases exponentially with decreasing RZS.

During parametric testing when operating conditions could be controlled so that the primary air/fuel ratios were relatively constant, the RZS could be held close to 0.90 without incurring excessive CO because the cyclone O_2 varied less than it did under normal boiler operating conditions. A RZS of 0.90 with only a small deviation from the target value was achievable during parametric testing. However during long-term testing the primary air/fuel ratio varied more widely. If the RZS for long-term testing had been targeted at 0.90, the minimum RZS during load swings would likely have been 0.85, which would have caused excessive CO emissions (1,000+ ppm). Raising the target RZS to 0.94 provided a margin of safety. With this target RZS the probability of the RZS falling below 0.90 and consequently excessive CO emissions was minimized, but at the expense of higher NO_x emissions.

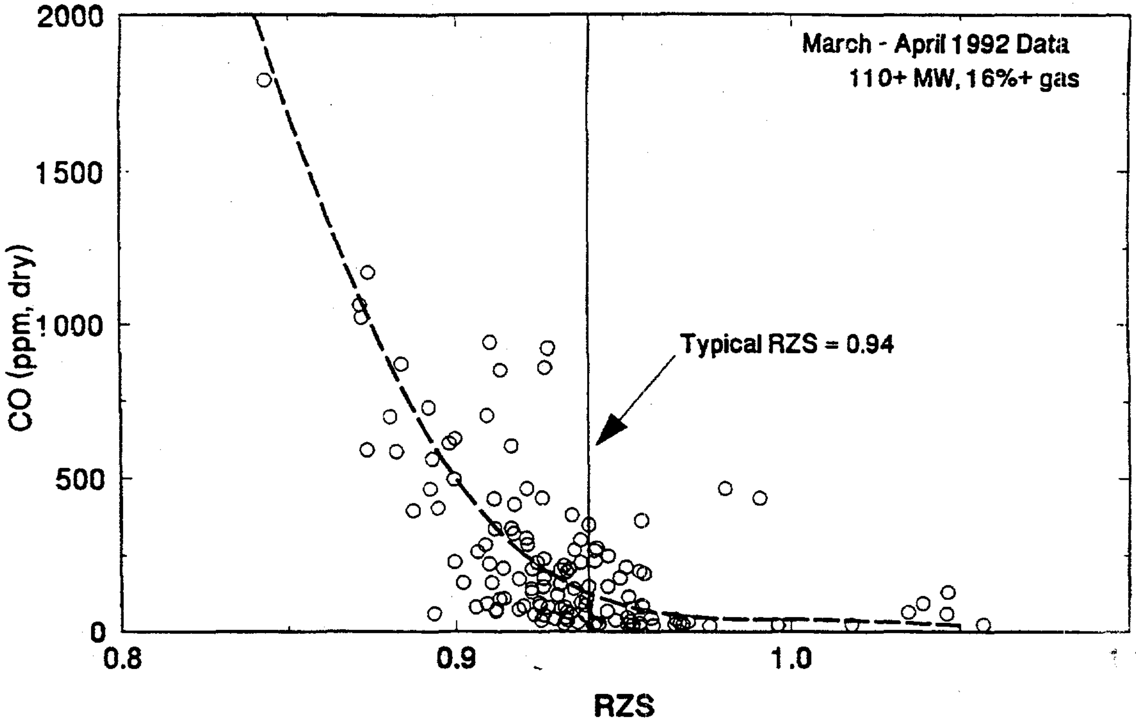


Figure 13-8
Variation of CO Emissions with RZS at Full Load

Effect of Unsteady Operation on NO and CO Emissions

As shown in Figures 13-7 and 13-8, NO_x emissions vary essentially linearly with RZS while CO emissions increase exponentially with decreasing RZS. Though NO_x emissions would be nearly identical under steady vs. unsteady operation (assuming the average RZS stayed the same) the CO emissions would be substantially higher. For example, at a steady 2.0% cyclone O_2 for one hour, the NO_x and CO emissions would be 330 and 50 ppm, respectively. If the unit were to then operate with the cyclone O_2 swinging between 1.4 and 2.6%, the average cyclone O_2 for the hour would still be 2.0%, and the average NO_x would also be unchanged at 330 ppm, but the average CO would be much higher at 215 ppm, a four-fold increase.

Variations in air/fuel ratio between cyclones can also lead to radical variations in CO concentrations. Since the available measurements only showed the overall reburn zone stoichiometry, there was no way to identify whether the air/fuel ratios of the individual cyclones were uniform or highly divergent. Figure 13-8 shows variations in CO concentrations during long-term tests in March and April 1992 from less than 25 to more than 925 ppm for reburn zone stoichiometry between .90 and .95. This range of CO concentrations indicates that wide variations in air/fuel ratios to the cyclones could have existed during the long-term testing.

Increased Variance of RZS About Target Value

During long-term testing the reburn system controller modulated reburn fuel flow according to coal flow. If primary air/fuel ratios had been held constant, then the RZS would have been relatively constant. However, under normal boiler operating conditions, considerable variation in primary air/fuel ratio did occur. Older boilers, which typically have older control systems, will generally show more variation than a newer boiler which is equipped with a more modern control system. At Niles the control system was replaced and upgraded in 1987; however, the sensors and drivers for some of the components, damper drives for example, are still original equipment. Most of the variation in RZS occurred because of changes in cyclone exit O_2. Reburn fuel input, by comparison, was held relatively constant between 16 and 18 percent of the heat input basis.

Commercial Potential of Gas Reburn for NOx Control

Effect of Boiler Load

As noted earlier (Figure 13-7), the percent NO_x reduction decreased with decreasing load even with the same percentage of reburn fuel. However, the baseline NO_x also decreased with decreasing load; the result being that the quantity of NO_x produced on an absolute basis stayed relatively constant throughout the range where reburn could be employed, see Figure 13-9. The reburn system was designed to operate at a constant 16% reburn fuel input down to 80 MW; from 80 MW to 65 MW the reburn fuel was designed to be ramped from 16% to 0%. Because of potential adverse effects on slag tapping, it was the operator's judgment to not operate the reburn system below 80 MW; Figure 13-9 reflects this by showing no NO_x reduction at loads of 75 MW and lower. More favorable coal properties (lower ash fusibility temperatures) could have facilitated reburn system operation down to the 65 MW design point. Long-term, cumulative NO_x emissions with reburning would be a weighted average of the NO_x produced at the actual loads experienced during normal boiler operation. As inferred from Figure 13-9, NO_x emissions are a function of the boiler duty and therefore base loaded units can realize lower NO_x emissions than peaking units. However, even if reburning cannot be used below some critical load, the overall effect is a levelization of NO_x emissions on an absolute (tons/hr) basis, throughout the entire load range.

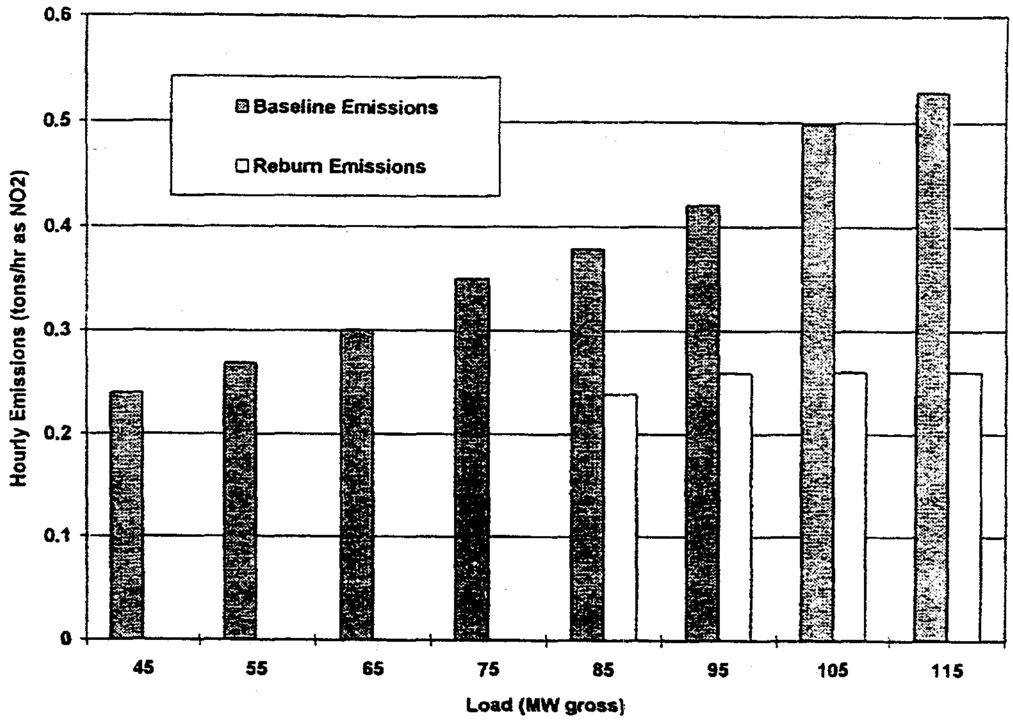


Figure 13-9
Reburn Effectiveness at Niles Unit No. 1 for Different Loads

Suitability of Gas Reburn for Seasonal NO_X Control

Gas reburning may have good potential to a utility company on a seasonal basis. The price of natural gas is typically lowest in the summer. During summer, ambient ozone concentration (which is regulated under Title I of the 1990 Clean Air Act Amendments) tends to peak because of the long duration of sunlight available to promote ozone formation reactions. NO_x is a precursor to ozone formation, and controlling NO_x emissions has been demonstrated to be a necessary part of reducing ozone concentration for most areas that are in non-attainment. During the summer months, most units in a utility system are operated at close to maximum capacity, the load at which the reburn process has been demonstrated to be most effective. Since most of the cost of reburn system operation is the fuel cost differential between natural gas and coal, the operating cost differential is at its minimum during the summer months. The combination of maximum effectiveness and minimum operating cost for reburn system operation during summer suggests that natural gas reburning is an ideal candidate technology for seasonal NO_x control. Also, the creation of emission allowances, through the substitution of gas (which contains little or no sulfur) for coal, which almost always contains sulfur, is likely to add further justification to reburning if the gas price is low enough.

Utility Operator's Assessment of NO_X Reduction by the Reburn Process

Operation of the system was fairly simple for the plant operators. The automated control system and interface with the main boiler controls allowed for a nearly invisible system for the operators. The reburn system operation put more heat into the superheat and reheat sections. This increased attemperator flow rates by about 1 to 5%. The resulting effects on boiler efficiency have been discussed in Section 12.

The overall NO_x reductions which gas reburning can achieve on a long-term basis depends on how the unit is loaded. The greatest NO_x reductions observed at Niles occurred only when the unit was operating at, or near, maximum load. At low load conditions (< 80% MCR), no NO_x reductions were achieved because the operators turned off the gas in order to keep the slag running in the cyclones and primary furnace.

The results presented elsewhere in this report demonstrate the need for additional research of gas reburning at other locations before any federal or state regulations are developed based on reburning as a long-term NO_x control technology for cyclone boilers. The Niles long-term testing began March 2, 1992, and ended June 19, 1992, a duration of only 3 1/2 months. During long-term testing, the Niles unit operated within a load range of 114 MW maximum down to 65 MW minimum. When the generating unit was operating above 80 MW during the 3 1/2 month test, the reburn system was not operated for roughly 50 percent of the time for a variety of reasons, as follows:

Operator Judgment - Though the reburn system was programmed to operated down to 65 MW, because of potential adverse effects on slag tapping, operators turned off the reburn system below 80 MW.

Furnace Casing Leak - The occurrence of a casing leak in the reburn zone required the reburn system to be shut off until the leak was repaired.

Reburn Fuel Guidepipe Leak - Water leaks occurred in several of the guide pipes necessitating shutting off the reburn fuel to the affected injectors.

Instrument Air Compressor Failure - Loss of compressed air for instruments and controls caused the reburn system to be turned off until the compressor was repaired.

Reburn Fuel Gas Control Valve Failure - Inability to accurately control natural gas flow rates caused the reburn system to be turned off until the valve was repaired.

The last three problems listed above should be resolvable with engineering changes. Potential solutions to the casing leak problem have been suggested. These will be discussed in Section 15; however, no solution has yet to be demonstrated. Finally, as discussed above, the minimum load at which the reburn system can be operated without incurring a slag tapping problem depends on cyclone exit temperatures and stoichiometry, and on the ash fusibility characteristics of the coal.

14

BOILER TUBE THICKNESS MONITORING PROGRAM

Description of the Program

During the planning for the reburn test program, Ohio Edison and Combustion Engineering recognized the need to monitor degradation of boiler tubing during the testing. The possibility of tube degradation existed because the reburn process altered the heat flux pattern within the furnace and produced substoichiometric (reducing) fuel/air gas mixtures downstream of the cyclones. To address the possibility of boiler tube degradation, a comprehensive boiler tube monitoring program was developed. The program included both non-destructive and destructive testing techniques to assess the possibility of corrosion on the waterwall tubes caused by the reducing atmosphere and long-term overheating and coal-ash corrosion damage on the superheater and reheater sections. The waterwall fireside corrosion was evaluated by ultrasonic thickness testing and corrosion probe monitoring. The assessment of superheater and reheater tube damage was performed by corrosion probe monitoring, remaining life evaluation by ultrasonic testing, and tube sample removal.

Testing Sequence

A baseline inspection of the unit with ultrasonic tube thickness measurements was performed in June 1990 during the installation of the reburn system. The first injection of natural gas into the unit took place on August 29, 1990. The parametric testing with the original reburn system took place during September through December 1990. A short outage at the end of December 1990 provided opportunity to obtain ultrasonic thickness data and a visual inspection for waterwall tube wastage. In October 1991, installation of the modified reburn system was completed. At that time another set of ultrasonic testing data was obtained and corrosion probes were removed. In the months following October 1991, several tests, including parametric, long-term, and water injection tests, were performed. In August of 1992 during the Unit 1 outage, an additional set of ultrasonic measurements was made and data was obtained for remaining tube life analysis.

Testing Locations

Measurements were made at several elevations of the lower furnace waterwalls, superheater sections, and reheat superheat section. Waterwall ultrasonic measurements were made on every third waterwall tube and target wall tube in the furnace at elevations of 914′, 902′, 896′, 890′, and

880′. Three readings per tube (left, center and right) were obtained. An additional strip was measured along the back wall upper bend at elevation 909′.

Because of the higher gas temperatures in the convection pass, ultrasonic thickness readings were also obtained on the horizontal reheater and superheater sections. Three readings per element were obtained for the horizontal reheater and each of the five stages of the secondary superheater. Internal oxide scale measurements were also obtained during the baseline testing and during the August 1992 outage.

In addition to the ultrasonic non-destructive testing, eight vertical temperature-controlled corrosion probes were installed through waterwall openings to measure the corrosion rates. Four probes were located at elevation 891′--two on the rear wall and one on each of the side walls. Two probes were located on side walls at elevation 904′, and two probes were located on side walls at elevation 928′. The design of the vertical waterwall corrosion test probes is shown in Figure 14-1. A horizontal corrosion probe was installed between the fourth and fifth stages of the secondary superheater. The design of the horizontal corrosion test probe is shown in Figure 14-2. The waterwall probes were constructed of three 2″ diameter test specimens of the following materials: SA192 carbon steel, SA213-T22 and SA213-TP304 stainless steel. In addition to these same materials, SA213-T11, T-91, and TP310 stainless steel were used in the corrosion probes for the superheater and reheater sections. The corrosion probe locations are shown in Figure 14.3.

Instrumentation

Ultrasonic thickness readings were obtained by Combustion Engineering's subsidiary, ABB AM Data, Inc. Thickness readings were taken by using a Kraut-Kramer Branson USK7 flaw detector with a contoured, dual-element 5MHz probe. Calibration was performed on a machined tube with known wall thickness. The calibration was checked after each set of readings. The tube surface was prepared by sandblasting to white metal. The couplant was a cellulose-gel type.

The remaining life analysis of the superheater and reheater sections was performed by using an oscilloscope and pulser receiver. The pulser receiver was a Panametrics Model No. TRX5052 (75 megahertz), and the oscilloscope was a Textronics Model No. 2246. The transducer was a single element delay line with a frequency range between 15 and 30 megahertz.

Ultrasonic Tube Thickness Test Results

Ultrasonic thickness (UT) readings were obtained on four different occasions over a 20-month period. The UT data are presented in Appendix A. The UT test results of the waterwall tubes are inconclusive and could not be used to determine a corrosion rate. In fact, close examination of plotted data revealed that many of the tubes gained wall thickness. The error in data may be explained by several factors: the equipment, the technique, and the variation in location and

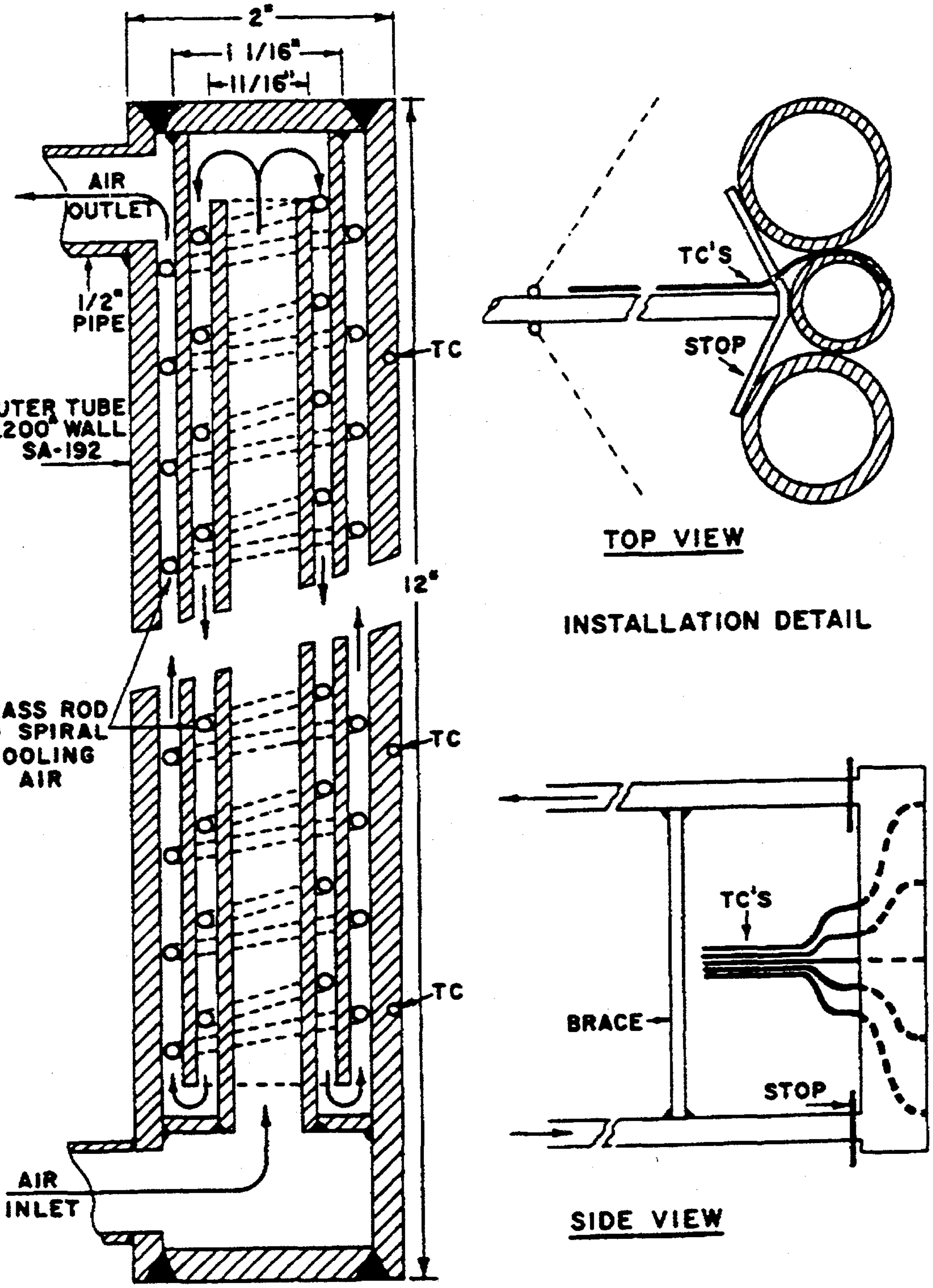


Figure 14-1
Vertical Corrosion Test Probe

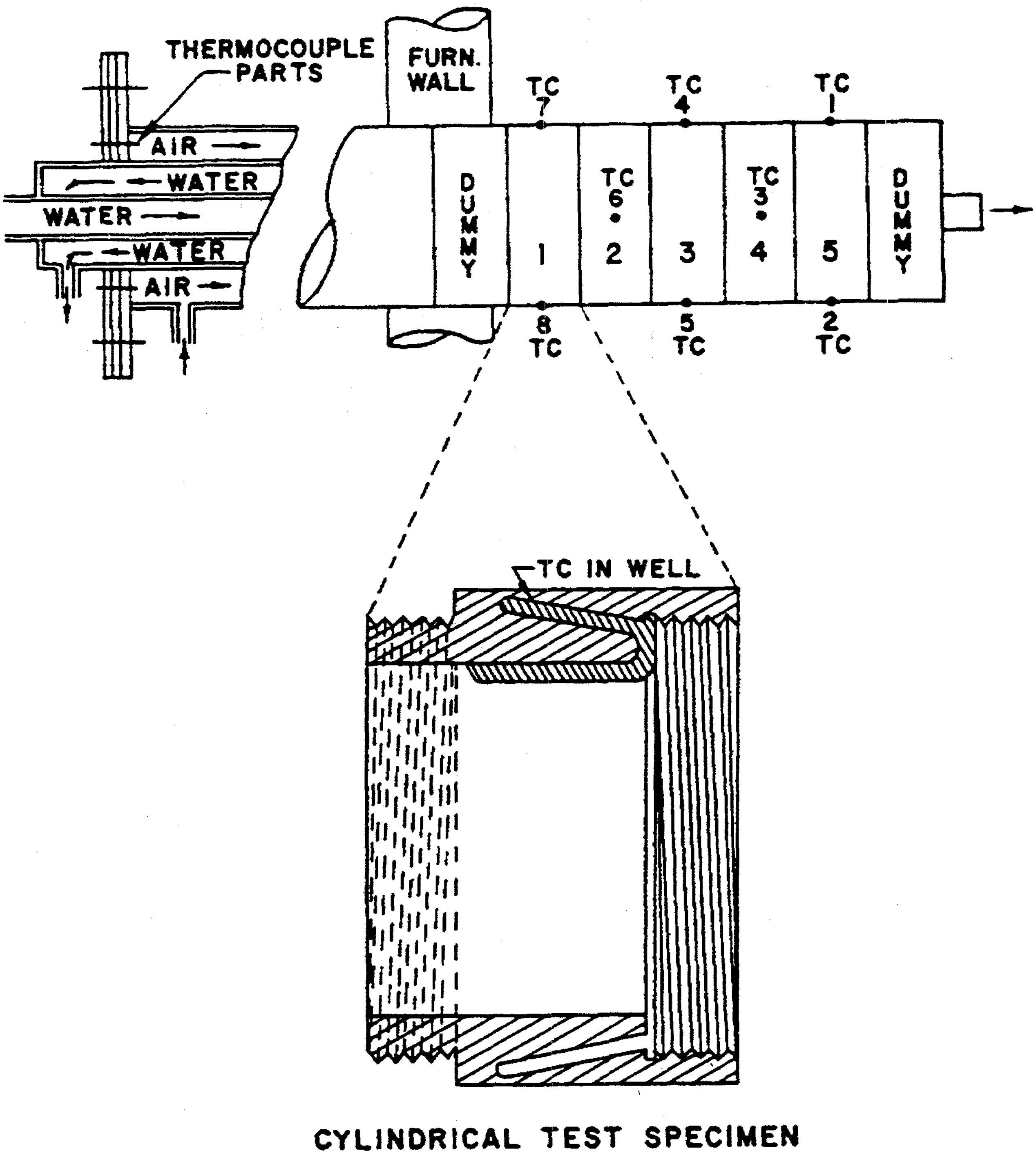


Figure 14-2
Horizontal Corrosion Test Probe

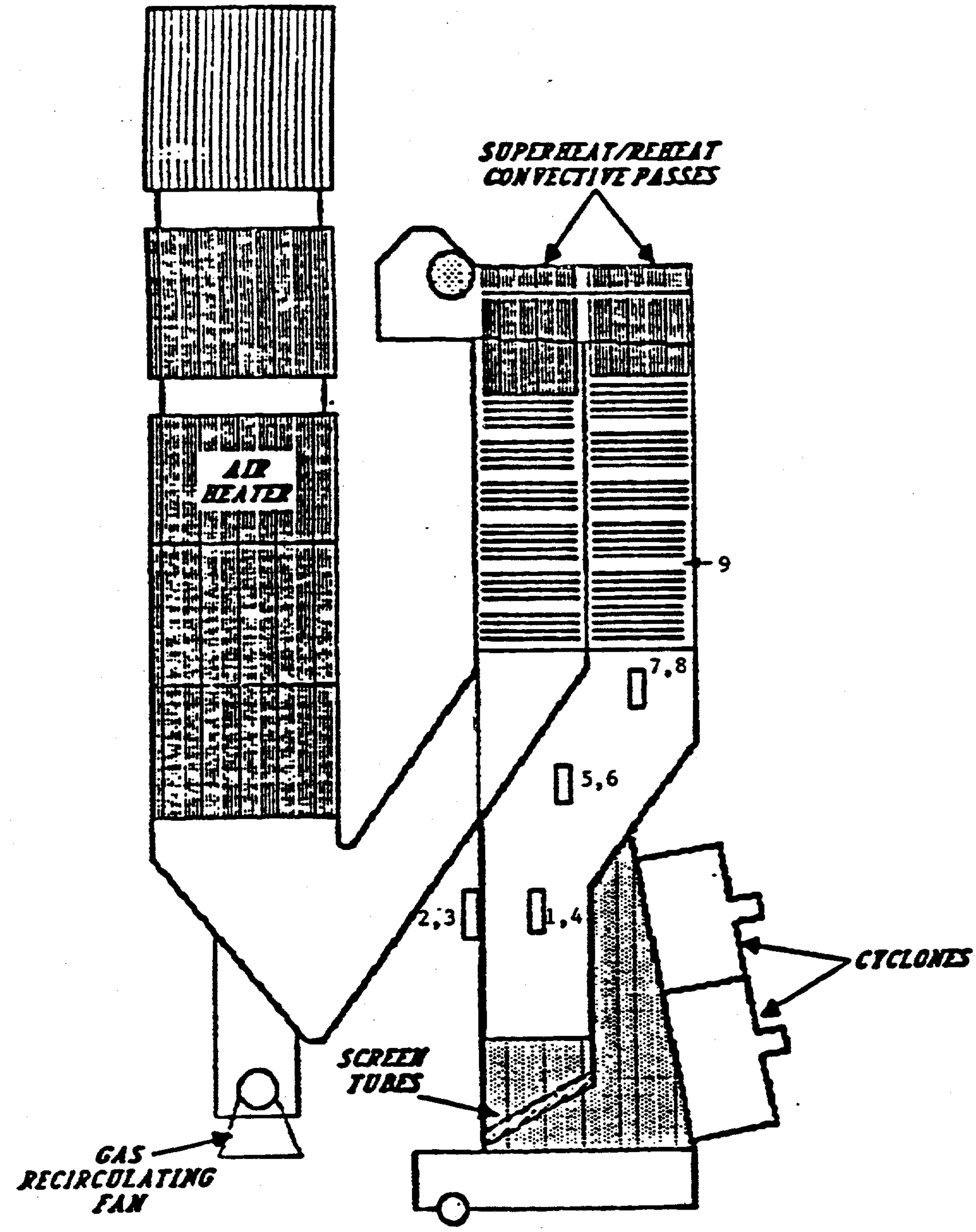


Figure 14-3
Corrosion Probe Locations

Eight vertical corrosion test probe locations are identified by Items 1 through 8. The horizontal corrosion test probe location is identified by Item 9.

calibration. More definitive insight concerning the effect of reburn on waterwall tubes was provided by visual inspection. During the December 1990 outage an inspection was performed on the waterwall tube surfaces. The inspection report is given in Appendix B. The examination revealed that the tube surface appeared to be unaffected by reducing atmosphere corrosion.

UT measurements of the superheater and reheater sections showed areas of erosion/corrosion. Although subject to the same errors mentioned above, the wall loss was significantly more pronounced. Ultrasonic thickness measurements of the superheater and reheater sections, following operation of the original reburn system, showed areas with an approximate 10% wall loss, with wastage in areas of the fifth stage superheater as high as 0.100" between the June 1990 measurements before the initiation of reburn operation and October 1991 which was before the initiation of testing of the modified system. Indicated tube loss is thought to be from a combination of erosion and corrosion. Tube wall thickness changes during testing of the modified reburn system (shown by measurements in October 1991 and August 1992) was significantly less and in several instances measurements of the superheater and reheater sections showed an inconsistent data pattern with smaller wall thicknesses in October 1991 than August 1992.

Because tube wastage was not uniform, it is believed that erosion was the larger contributing factor between erosion and corrosion. The reduced tube wastage during operation of the modified reburn system (without FGR) is explained by the fact that flue gas mass flows/velocities during modified reburn system operation were returned to base-case levels and in this way wastage due to erosion was minimized.

Remaining Tube Life Analysis Using Oxide Scale Measurements

The superheater and reheater sections were inspected for oxide scale and wall thickness before and after the reburn project. The oxide scale thickness is representative of the operating temperature which when combined with the time of operation can be correlated to a Larson-Miller parameter. The dimensions of the tubing along with wall thickness are used to calculate the mean diameter stress. Remaining life is predicted based on a linear oxide scale growth and wall loss rate.

After reviewing the oxide scale data it was found that the results of the initial, baseline inspection gave remaining life values lower than the final inspection values. The oxide scale readings obtained during the initial inspection were always assumed to be at least 0.006", thus producing a lower remaining life value. When the measurements were made during August of 1992, a new technology allowed the technician to measure scale thicknesses below 0.006". Since a valid comparison of remaining life before the initiation of reburn testing and after the completion of reburn testing was not possible, the oxide scale tube life analysis could not be used to evaluate the effect of gas reburn on the superheater or reheater tube life.

Corrosion Probe Tests

The corrosion probes were installed for the parametric testing conducted between January and October 1991. The results of the corrosion evaluation are attached in Appendix C. The corrosion probe analysis revealed that virtually no corrosion had occurred on the materials on most of the probes at all locations. Two of the probes however did indicate severe corrosion rates which were attributable to loss of probe cooling air.

Conclusions

A reburn system was installed in Niles Unit 1 at the end of June, 1990. Prior to the installation Ohio Edison and Combustion Engineering developed a series of tests to evaluate corrosion damage to the waterwall, superheater, and reheat superheater tubing. The key findings are as follows:

- The ultrasonic thickness testing in the waterwall sections was inconclusive. Changes in tube wall thickness were below the threshold of sensitivity of the UT measurement technique. However, visual inspection of the waterwalls during the December 1990 outage revealed that the tube surface appeared to be unaffected by reducing atmosphere corrosion.
- Ultrasonic thickness measurements of the superheater and reheater sections following operation of the original reburn system showed areas with an approximate 10% wall loss, with wastage in areas of the fifth stage superheater as high as 0.100". Tube wall thickness changes were significantly less during testing of the modified reburn system. The reduced tube wastage during operation of the modified reburn system (without FGR) is explained by the return of flue gas mass flows/velocities to baseline levels during modified reburn system operation, thereby minimizing wastage due to erosion. Because tube wastage was not uniform, it is believed that erosion was the larger contributing factor between erosion and corrosion.
- The remaining superheater/reheater tube life analyses performed before and after the reburn project were inconclusive concerning any degradation due to high temperature oxidation. Final inspection values gave higher remaining tube life values than did initially obtained values.
- Corrosion probe tests showed very low corrosion rates. In two instances when corrosion rates were high, the wastage was attributed to loss of cooling air to the probe.

15

APPLICATION OF REBURNING TO PRESSURIZED FURNACES

Background

The application of reburn technology to pressurized furnaces such as Niles Unit No. 1 can create unfavorable situations if a leak develops in the casing surrounding the furnace in the vicinity of the reburn zone because the reburn process generates a fuel-rich gas mixture for converting NO_x into N_2. Furnace gases usually are a mixture of the normal combustion products: carbon dioxide, water vapor, nitrogen, and a slight concentration of oxygen. However, during the reburn process the fuel-rich combustion products in the reburn zone contain carbon monoxide, a toxic gas. In addition, some mixtures of fuel-rich combustion products can be in the flammability range, depending on the proximity of the leak to the reburn fuel injectors, and therefore can create a hazard. During long- term testing on April 16, 1992, five "flameletts" about two feet long were observed attached to a corner of the furnace at the elevation of the reburn zone. Apparently, a furnace gas leak occurred in the reburn zone and gases made their way through the casing to the atmosphere where, with sufficient oxygen and being combustible gases, they proceeded to burn. There was no indication that reburning had caused the casing leak; as a matter of fact, leaks can occur during normal furnace operation of pressurized units. However leakage of combustible gas creates a different situation than leakage of normal products of combustion.

Resolution of the Problem

Discussions were held with project personnel, sponsors, and consultants to identify and resolve the leakage problem. The issue was addressed in two categories: (1) what to do to assure safety during the long- term reburn tests, and (2) what to do for an acceptable solution for commercial application of reburn technology to pressurized furnaces.

Regarding category (1), it was decided that the most reasonable approach was to find and repair the leak and institute a monitoring plan that would allow early detection of any new gas leaks that might occur. The casing leak was found and repaired. The monitoring plan incorporated the use of a portable hand-held gas analyzer which the boiler operators carried and used throughout the plant during normal once-per-shift walkdowns of the unit. Long term reburn testing was continued to completion.

Regarding category (2), several possible commercial solutions were suggested. A number of options were considered: (1) convert pressurized units to balanced draft by adding an induced draft fan and associated equipment, (2) convert tangent tube pressurized units such as Niles No. 1 to fusion welded walls by adding fusion welds between the tubes, (3) erect an enclosure around the reburn zone which would operate at a slightly higher positive pressure than the furnace pressure to assure that any leakage would be into the furnace and (4) erect a "hood-like" structure around the upper part of the furnace so that gas composition could be constantly monitored for possible changes. It is unlikely that options (1) and (2) could be economically justified, given the remaining life of most cyclone units and the existence of competing technologies. However, options (3) and (4) would be much less capital-intensive and could be configured to ensure safe reburn system operation.

It should be noted that "commercial" resolution of this unanticipated problem was beyond the program workscope. Indeed, discovery of this problem is an excellent example of why R&D demonstration programs are conducted. The preferred selection between these alternatives depends upon site-specific technical as well as economic considerations and can therefore only be decided by a detailed technical and economic analysis.

16

REBURN SYSTEM ECONOMICS

Introduction

There are currently about 100 cyclone-fired boilers operating in the United States. These units range in size from about 15 to 1150 MW and were commissioned between the late 1940's through 1981. Baseline NO_x emissions from these cyclone units range from 600 to 2000 ppm corrected to 3% O_2 (0.85 to 2.7 lb NO_x/mmBtu). These emissions can be reduced by 50 to 70% using natural gas reburning. Since cyclone boilers do not employ burners in the conventional sense, reburning is the only viable in-furnace NO_x reduction technology that has been proposed for NO_x reduction for cyclone units. Other technology options include staged combustion and post-combustion NO_x control systems (selective non-catalytic reduction, selective catalytic reduction, SNOX). Staged combustion is unacceptable for retrofit of cyclone furnaces due to the potential for unburned carbon, increased cyclone watertube corrosion, and slag tapping problems. The choice between reburning and the post-combustion technologies is driven by cost (dollars per ton of NO_x removed) as well as the impact of the technologies on boiler availability, reliability and performance.

The natural gas reburning demonstration at Niles resulted in practical design and operating experience that can be applied to other cyclone-fired boilers. In addition to the Niles demonstration, there have been two other reburning demonstrations on cyclone boilers; one of them employing natural gas and the other coal as the reburning fuel (Farzen, et al. (1993); Folsam et al. (1995)). However, to apply reburn technology commercially, the process must not only be technically feasible but also economically viable to be chosen over post-combustion processes for NO_x control. A study was conducted to evaluate reburning from an economic perspective as a NO_x reduction technology for the entire cyclone boiler population using the Niles experience as the basis. The Niles results were applied to five other cyclone boilers which cover a range of sizes, ages, furnace configurations, cyclone arrangements, and megawatt ratings. This section summarizes the findings of the study and reaches conclusions for the technical and economic viability of natural gas reburning for cyclone boilers.

Basis for Study

Cyclone Boiler Population Application Criteria

The first criterion for applying natural gas reburning to cyclone-fired boilers is age of the unit. The project team determined that a boiler should have at least 10 years of operation remaining in its expected lifetime to justify the capital investment for any combustion modification or post-combustion equipment. If it is assumed that 50 years is a reasonable boiler lifetime from start-up date and that the retrofit of reburning equipment will be completed in 1997, then the boilers that are "eligible" for reburning retrofits are listed in Table 16-1.

Table 16-1
89 Cyclone Boilers with 1957 and Later Start-up Dates

Utility/Station	B&W Contract No.	MW Rating	Start-up Date	Fuel Type
Eastman Kodak, Rochester, NY	RB-230	~60	1957	bit
AEP/Ohio Power, Muskingum river #3	RB-248	225	1958	bit
Tampa Electric, Gannon #1	RB-254	105	1957	bit
International Paper, Mobil #1, #2	RB-255	~70 each	1957	bit
Jersey Central P&L, Sayreville	RB-256	133	1960	bit
AEP/Columbus & Southern, Conesville #1	RB-265	136	1958	bit
AEP/Ohio Power, Muskingum River #4	RB-268	225	1958	bit
Consolidated Water & Power, Biron	RB-274	16	1957	bit
AEP/Ohio Power, Kammer #1, #2	RB-280	225 each	1961	bit
TVA, Allen #1, 2, 3	RB-289	330 each	1964	bit
Tampa Electric, Gannon #2	RB-290	115	1959	bit
International Paper, Pine Bluff #1, 2	RB-291	~70 each	1958	bit
Detroit Edison, St. Clair #5	RB-292	325	1960	bit
Rhinelander Paper, St. Regis	RB-296	~30	1959	bit
AEP/Ohio Power, Kammer #3	RB-297	225	1961	bit
Atlantic City Electric, Deepwater #1	RB-299	79	1960	bit
AEP/Columbus & Southern OH, Conesville #2	RB-303	136	1959	bit
Arkansas P&L, Ritchie #1	RB-305	356	1961	bit
Commonwealth Edison, Joliet #6	RB-311	360	1960	bit

**Table 16-1 (Cont'd.)
89 Cyclone Boilers with 1957 and Later
Start-up Dates**

Utility/Station	B&W Contract No.	MW Rating	Start-up Date	Fuel Type
Wisconsin P&L, Nelson Dewey #1	RB-312	100	1960	bit
United Illuminating, Bridgeport Harbor #1	RB-320	75	1962	bit
Missouri Public Service, Sibley #1	RB-327	50	1960	bit
W. VA Pulp & Paper, Luke MD	RB-331	~60	1960	bit
Public Service of NH, Merrimac #1	RB-337	114	1961	bit
Nebraska Public Power, Sheldon #1	RB-338	105	1961	bit
Monongahela Power, Willow Island #2	RB-342	165	1961	bit
Tampa Electric, Gannon #3	RB-346	160	1960	bit
Missouri Public Service, Sibley #2	RB-347	50	1963	bit
Central Electric Power, Chamois #2	RB-348	48	1961	bit
Iowa Electric, Sutherland	RB-353	75	1962	bit
Kansas City BPU, Kaw #3	RB-359	66	1963	bit
Tampa Electric, Gannon #3 and 4	RB-361	180	1964	bit
Commonwealth Edison, State Line #4	RB-365	389	1963	bit
Baltimore G&E, Crane #2	RB-366	191	1963	bit
Atlantic City Electric, B.L. England #1	RB-368	125	1963	bit
Wisconsin P&L, Nelson Dewey #2	RB-369	100	1962	bit
NIPSCO, Bailly #7	RB-372	194	1964	bit
Iowa Public Service, Neal #1	RB-377	147	1964	bit
Owensboro Municipal Utility, Smith #1	RB-386	150	1965	bit
Northern States Power, Riverside #8	RB-390	228	1964	bit
Atlantic City Electric, B.L. England #2	RB-409	150	1965	bit
Kansas City BPU, Quindaro #3	RB-421	75	1968	bit
Associated Electric Coop., Hill #1	RB-427	175	1970	lig
St. Joseph P&L, Lake Road #1	RB-430	75	1969	bit
Associated Electric Coop., Hill #2	RB-434	270	1969	lig

Table 16-1 (Cont'd.)
89 Cyclone Boilers with 1957 and Later Start-up Dates

Utility/Station	B&W Contract No.	MW Rating	Start-up Date	Fuel Type
Nebraska Public Power, Sheldon #2	RB-438	120	1968	bit
Wisconsin P&L, Edgewater #4	RB-442	330	1969	bit
Empire District Electric, Asbury #1	RB-447	200	1970	bit
Minnkota Power, Young #1	RB-457	235	1970	lig
Associated Electric Coop., New Madrid #1	RB-466	580	1973	lig
Associated Electric Coop., New Madrid #2	RB-483	600	1977	lig
Basin Electric, Leland Olds #2	RB-489	400	1974	lig
Otter Tail Power, et al, Big Stone #1	RB-490	400	1974	lig
Southern Illinois Power Coop., Unit 4	RB-560	175	1978	lig
Otter Tail Power, Coyote #1	RB-563	456	1981	lig
Southern Illinois Power Coop., Unit 5	RB-589	350	1980	lig
AEP/Ohio Power, Philo #6	UP-1	125	1957	bit
AEP/Ind. & Mich. Elec., Breed #1	UP-2	450	1960	bit
Baltimore G&E, Crane #1	UP-6	190	1961	bit
AEP/Ind & Mich. Electric, Tanners Creek #4	UP-9	580	1964	bit
TVA, Paradise #1	UP-10	704	1963	bit
TVA, Paradise #2	UP-11	704	1963	bit
Public Service E&G, Hudson #1	UP-12	420	1964	bit
Hartford Electric, Middletown #3	UP-16	240	1964	bit
CIPS, Coffeen #1	UP-18	365	1965	bit
Union Electric, Sioux #1	UP-19	489	1967	bit
Union Electric, Sioux #2	UP-20	489	1968	bit
NIPSCO, Bailly #8	UP-29	422	1968	bit
Commonwealth Edison, Kincaid #1, 2	UP-30	660 each	1967	bit
Northern States Power, King #1	UP-36	574	1968	sub
Public Service of NH, Merrimac #2	UP-42	350	1968	bit
Missouri Public Service, Sibley #3	UP-45	419	1968	bit

Table 16-1 (Cont'd.)
89 Cyclone Boilers with 1957 and Later Start-up Dates

Utility/Station	B&W Contract No.	MW Rating	Start-up Date	Fuel Type
TVA, Paradise #3	UP-49	1150	1969	bit
Illinois Power, Baldwin #1	UP-61	605	1970	bit
NIPSCO, Michigan City #12	UP-76	500	1974	bit
CIPS, Coffeen #2	UP-82	600	1972	bit
Illinois Power, Baldwin #2	UP-83	600	1973	bit
Commonwealth Edison, Powerton 35-1, 35-2	UP-89	430 each	1972	sub
Kansas City P&L/KG&E, La Cygne #1	UP-90	844	1973	sub
Commonwealth Edison, Powerton 6-1, 6-2	UP-103	430 each	1975	sub
NIPSCO, Schahfer #1	UP-112	520	1976	bit
Total Number 89				

About 160 cyclone boilers have been built in the United States. Table 16-1 lists 89 units with 1957 or later start-up dates; this represents the number of retrofittable units according to the earlier guidelines assuming a 50-year life and having 10 or more years of useful life remaining. Out of this list, one unit has already been retired, one unit already has a reburning system, and four have been targeted for SNCR retrofits. Therefore, the reburning retrofit candidates are reduced to 83.

These boilers can be classified further by megawatt rating, main furnace configuration, and cyclone configuration. Older units like Niles often fire the cyclones into a primary furnace to maximize slag rejection. Slag droplets entrained in the cyclone exit gas are impinged against the target wall of the primary furnace. The gases must pass below the target wall, through a bank of screen tubes, then upward through the main furnace to the furnace exit. Such units are often short and wide, and present challenges to the reburning system designer for placement of fuel and air injectors where adequate mixing rates and reaction times are available.

Newer units were usually designed with open furnaces and with cyclones mounted on single or opposed walls. Boilers with open furnaces are usually tall and thin, and their width is determined by the number of cyclones that must be accommodated. Figure 16-1 from Steam, Its Generation and Use (1992) illustrates the different cyclone furnace arrangements.

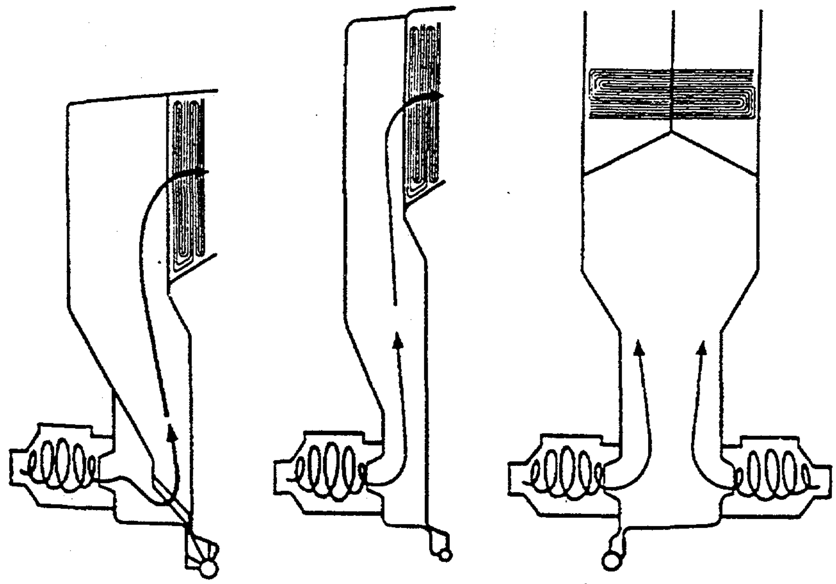


Figure 16-1
Firing Arrangements Used for Cyclone Furnaces (from Steam, Its Generation and Use, with permission from Babcock and Wilcox)

The boilers chosen for further study allowed the following comparisons:

- primary furnace versus open furnace (one-wall-fired)
- one-wall versus opposed wall firing
- one versus two cyclone furnace elevations
- pressurized versus balanced draft operation
- designs from the 1950's versus 1960's.

Table 16-2 lists the boilers (anonymously); Section 3 of this report will provide additional description of each unit.

Reburn System Design Criteria

The criteria used for the design of the Niles reburning system were confirmed during the demonstration tests. Those criteria are listed in Table 16-3. Changes to the commercial reburn system design resulting from the test program are discussed below.

One of the significant findings of the testing at Niles was that effective penetration and mixing of natural gas reburn fuel was achieved without the use of flue gas recirculation (FGR). The elimination of FGR was considered sufficiently important both from an operational and an economic standpoint that reburn systems employing direct injection of natural gas were used as

Table 16-2
Study Boilers

Unit	Start-up Year	Gross MW Rating	No. of Cyclones	Cyclone Arrangement	Draft	Furnace Type	Furnace Width, Ft.	Furnace Depth, Ft.	*Furnace Height, Ft.	Normal Residence Time, s
Niles Unit #1	1953	115	4	2 over 2 Front Wall	Press.	Primary	36	13	~43	1.6**
Unit A	1969	75	2	Front Wall	Press.	Open	24	14	38.7	0.9*
Unit B (Decom.)	1957	125	3	Front Wall	Press.	Primary	34	10.5	19.2	0.5**
Unit C	1958	225	5	2 over 3 Front Wall	Press.	Primary	48	16	20.5	0.8**
Unit D	1968	420	8	2 over 2 Opposed Wall	Bal	Open	36	27	90.0	1.1*
Unit E	1970	605	14	3 over 4 Opposed Wall	Bal	Open	60	33	116.8	2.0*

* ℄ of top cyclones to furnace arch
** Main furnace only, screen tubes to furnace arch

Table 16-3
Reburn Design Criteria for Niles

- Cyclones operate at SR of 1.1; 50% cyclone turndown
- Inject reburn gas as close as possible to cyclones (T ~ 2700 F)
- No FGR for furnace depth less than 17 ft (34 ft for opposed-fired)
- Reburn zone S.R. = 0.90 at full load
- Reburn zone residence time (nominal) = 0.6 s at full load
  - minimum of 0.3 s
  - maximum of 0.8 s
- Burnout zone residence time (nominal) - 0.7 s at full load
  - minimum of 0.5 s

the basis for the economic evaluation. At Niles, the furnace depth at the point of natural gas injection was 13 ft. The gas jets, injected at sonic velocity, were observed to reach the opposite wall. It was estimated that the jets could have penetrated several feet further had the furnace been deeper; it was estimated that no FGR would be required as long as the boiler depth is less than 17 ft for one-wall-fired boilers or 34 ft for opposed-fired boilers with reburn nozzles installed on both the front and rear walls. Since the largest opposed-fired cyclone boiler ever built (TVA, Paradise Unit #3 - 1150 MW) is only 33-ft deep (by 96-ft wide), it is concluded that FGR would not be required on any cyclone-fired boiler using natural gas as the reburn fuel.

Location of reburn fuel and additional air injectors will be based on residence time available for mixing, and affected by structural interferences that could prevent the ideal location from being chosen. Reburn fuel injectors should be placed as close to the cyclone outlets as possible since higher temperatures drive the NO_x reduction reactions. Side spacing between reburn fuel injectors should be close (4 to 8 ft) to assure that natural gas rapidly contacts the products of combustion from the cyclones. Vertical distance between fuel injectors and additional airports should provide enough time for mixing and NO_x reduction to take place. Theoretically, additional air port locations should be chosen to assure burnout of gaseous hydrocarbon fragments remaining after partial combustion of the reburning gas. Reaction should be rapid, so mixing rates will dominate. However, in commercial reburn systems, the additional air must also burn any carbon carryover from the cyclones that would normally have burned where the reburning zone has been located.

Reburn System Design and Economics

Five boilers were chosen from the cyclone boiler population to be subjects of a technical and economic assessment. For each unit, a general arrangement of reburning equipment was prepared, NO_x emissions before and after reburning were estimated, and rough capital and operating costs were scaled from the Niles experience. The EPRI Technical Assessment Guide, EPRI (1989), was used for the economic estimates, except a detailed breakdown of process capital was beyond the limited scope of this assessment.

Specifically, the capital cost of reburning at Niles was taken from Borio et al. (1991) with adjustments in capital costs for the change from the original reburn system to the modified system, adjustments due to productivity gains, and adjustments for price escalation between 1991 and 1995. The changes to the modified reburn system included elimination of the flue gas recirculation fan, motor, controls, and ductwork, simpler reburn fuel injectors, and simpler modifications to the furnace water walls. It was estimated that these changes would reduce the capital cost by $1.0M relative to the $4.22M capital cost presented by Borio et al. (1991) for the original reburn system. The capital costs for this study are presented in 1995 dollars. It was estimated that capital cost escalation between 1991 and 1995 would be balanced by cost savings due to productivity gains between 1991 and 1995. Therefore the estimated process capital cost for Niles in 1995 dollars is $3.22M.

To extrapolate Niles cost experience to different sized cyclone furnaces, the "factor" method was used. In this method the Niles costs were scaled by the square root of the megawatt rating of each unit studied as shown below:

$$\text{Unit process capital} = (\$3.22\ \text{M})\left(\frac{\text{Unit MW}}{\text{Niles MW}}\right)^{1/2}$$

The factor method was appropriate for this study since the design of the reburn system equipment for the other units would be similar to the Niles equipment and costs would be expected to be analogous to unit sizes. The unit process capital calculated by the above equation was applied in the EPRI TAG to derive capital and O&M costs.

The economic viability of reburning for Niles and each of the five study boilers is characterized by the NO_x removal cost effectiveness which is the cost, in dollars per ton of NO_x removed. The NO_x removal cost effectiveness of natural gas reburning depends on these factors:

1. NO_x removal efficiency over the operating range of the boiler

2. The load profile of the boiler

3. Minimum boiler load at which reburning can be applied

4. The differential in cost between coal and natural gas

The load profile of each individual boiler is an important economic variable in the calculation of the NO_x removal cost effectiveness because the investment and fixed operating costs for the NO_x control equipment are constant over the time period for amortization of the equipment but the quantity of NO_x removed over this time period is dependent upon the load profile of the boiler. Load profile is especially important for reburning in cyclone boilers for three reasons:

1. Turndown of individual cyclones is limited by the ability of each cyclone to maintain molten slag from the spout to the slag tap at the bottom of the unit. Minimum load for each cyclone is usually about 50% of full load heat input. When 18% of the heat input is

provided by the reburning fuel, the turndown range of each cyclone becomes 82% of its former value.

2. Many cyclone boilers do not have the flexibility to remove cyclones from service to achieve low load operation. Therefore, minimum cyclone load is often minimum boiler load especially when the number of cyclones is small.

3. At decreased load, the NO_x reduction usually decreases because the NO_x entering the reburn zone decreases, because the temperature in the reburn zone is lower (NO_x destruction slows down), and because cyclone outlet O_2 increases (especially when cyclones are taken out of service). An increase in cyclone outlet O_2 at a constant percentage of reburning gas results in a higher stoichiometric air-fuel ratio in the reburn zone and less NO_x destruction.

The sensitivity of NO_x reduction to load profile was explored during this study. The EPRI TAG method applies a 65% load factor to the full load NO_x emission potential to determine the amount of NO_x removed per year. This simplifying assumption does not take into consideration reduced NO_x control effectiveness at intermediate loads or the need to turn off the reburning fuel at very low load. Therefore, in addition to the EPRI TAG method, four load profiles were used to evaluate the cost impact on each case study boiler:

1. A load profile derived from the Niles long-term demonstration data (65% load factor).

2. A high load profile representative of today's most competitive base loaded units (82% load factor).

3. A typical base load profile for pulverized coal-fired boilers and larger cyclone-fired boilers where more load flexibility is available (65% load factor).

4. An intermediate load profile for units with relatively high operating costs (49% load factor).

Figure 16-2 shows the Niles load profile. Load data originally organized into 10 MW increments (i.e. time at 100 to 110 MW, 90 to 100 MW, etc.) were merged into three categories: 100% load (90 to 115 MW), 70% load (70 to 90 MW), and 50% load (40 to 70 MW). Time of day was arbitrarily selected but does not factor into the calculation. Figure 16-3 shows the other load profiles used in this study. Note that the Niles and the "typical" load profiles both produce the same load factor (65%), but differ in the amount of off-peak time spent at very low loads.

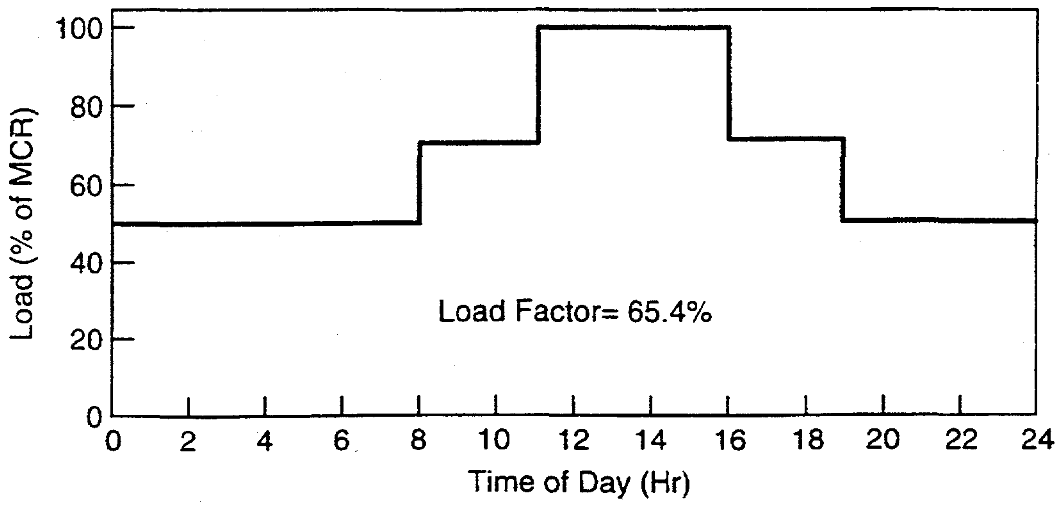


Figure 16-2
Niles Load Profile

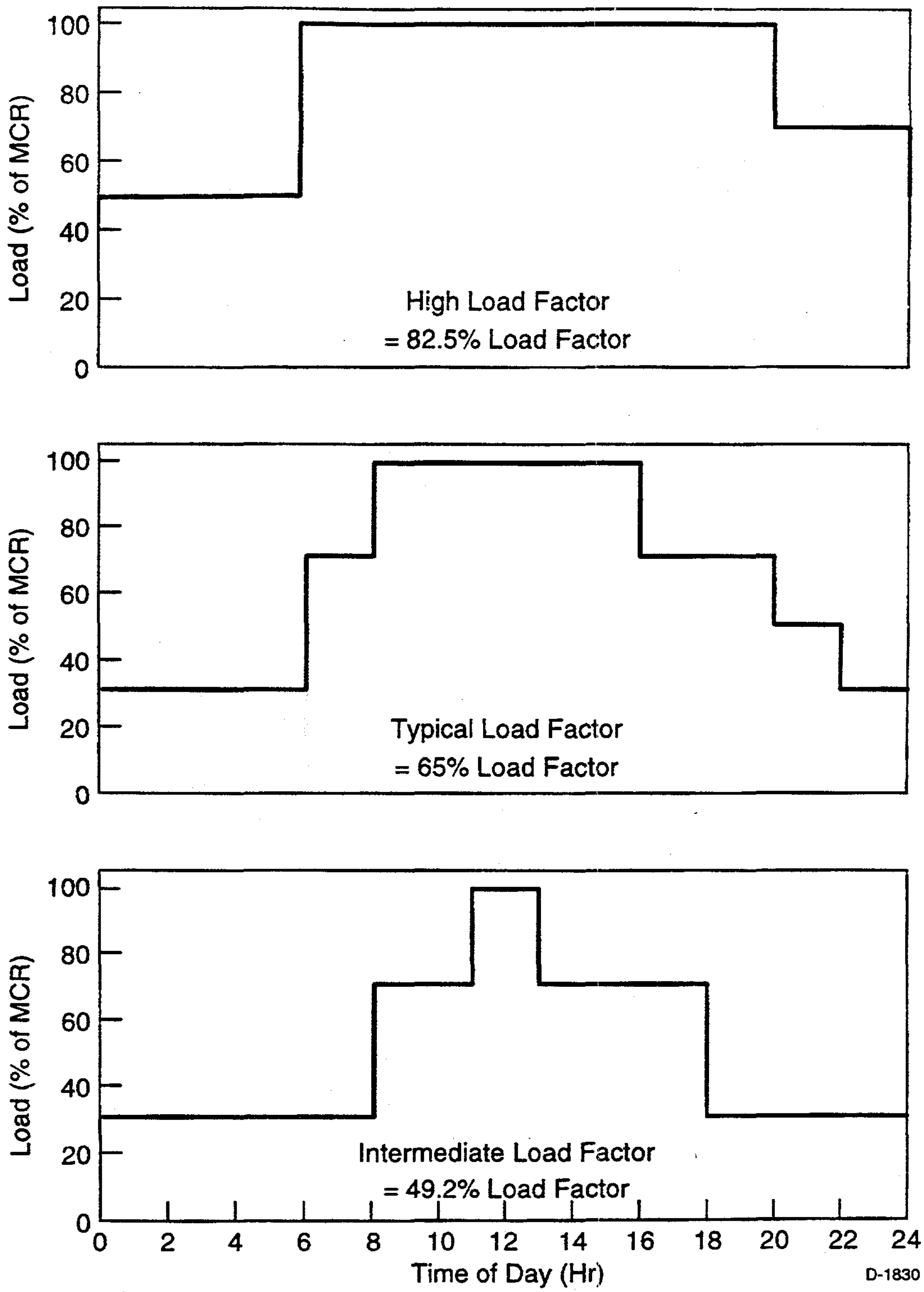


Figure 16-3
Load Profiles for High Load Factor (Base-Loaded) Units, Typical Coal-Fired Units, and Intermediate Load Factor Units

A summary of the reburning system designs for Niles and the five boilers is given in Table 16-4. The NO_x removal cost effectiveness for Niles Unit No. 1 and each of the study units are presented in the following subsections for a range of natural gas cost differentials. The costs are calculated using the EPRI TAG method and for one or more of the four load profiles discussed above, where applicable.

Niles Unit No. 1

The Niles reburning system design has been discussed elsewhere in this report, but is summarized here for completeness. Niles is a pressurized unit rated at 115 gross MW. Four cyclone furnaces arranged two over two (staggered) in the front wall fire into the primary furnace. Gases are forced downward by the target wall through the screen tubes to the main furnace, and then upward to the convective section. Figure 16-4 shows a sectional side view of Niles No. 1 prior to reburning retrofit.

To convert this unit to reburning, furnace penetrations were added to allow natural gas and burnout air injection. Five natural gas injectors spaced about 6 ft apart horizontally were added to the rear wall of the main furnace at elevation 880 ft. Two burnout air ports were arranged about 5 ft apart on both boiler sidewalls (total of four burnout air ports) at elevation 912 ft. The air port arrangement was not optimal since each air jet had to quickly penetrate at least half way across the 36-ft boiler width, but operation proved adequate as long as the cyclone combustors were operating with low CO and unburned carbon.

Table 16-4
Preliminary Design Summary

Unit	Gross MW	No. of Cyclones	FGR Required	No. of Reburn Fuel Injectors
Niles #1	115	4	No	5
Unit A	75	2	No	5
Unit B	125	3	No	5
Unit C	225	5	No	7
Unit D	420	8	No	12
Unit E	605	14	No	14

Unit	Reburn Zone Normalized Residence Time	No. of Burnout Air Injectors	Burnout Zone Normalized Residence Time	Estimated Min. Load, %	Estimated Min. Load w/Reburn, %
Niles #1	1.0	4	1.0	50	70
Unit A	0.77	5	0.88	50	67
Unit B	0.46	4	0.39	34	44
Unit C	0.46	4	0.55	30	40
Unit D	0.95	10	0.74	25	38
Unit E	1.18	14	1.72	29	49

Note: Normalized residence times are based on 1.0 for Niles Unit No. 1

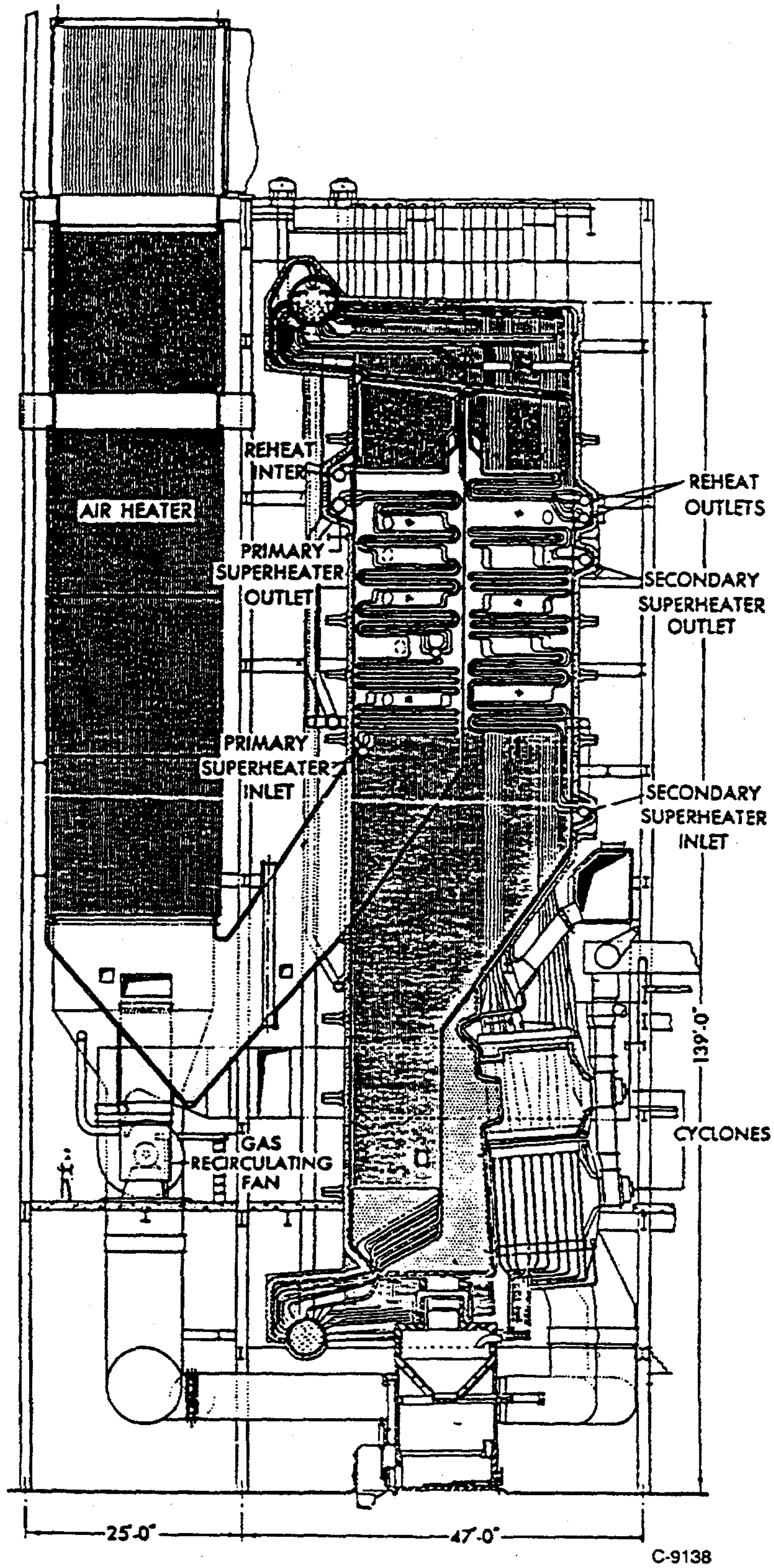


Figure 16-4
Niles Unit No. 1 Ohio Edison Company

The Niles boiler was a challenge for implementing natural gas reburning technology, but by no means the worst case. The main furnace contained adequate residence time to meet design criteria for NO_x reduction in the reburn zone and carbon conversion in the burnout zone. As the reader will see in the subsections that follow, other cyclone-fired boilers with primary furnace designs are not so generous.

The economics of reburning at Niles were summarized in previous ABB technical papers (e.g. Borio et al. (1991)). Certain capital costs specific to Niles (FGR fan replacement, asbestos abatement, an on-site natural gas pipeline, test ports for sampling and corrosion measurements) added approximately $1,000,000 to the process capital for this project. Elimination of these costs would reduce the total capital cost for a commercial reburning retrofit at Niles. Key economic factors for Niles calculated using the EPRI TAG are the following:

process capital	$3.22M
total plant investment	$3.70 M
total capital required	$3.91M
capital cost per kW	$34/kW
10-yr. levelized busbar power charge	6.35 mills/kWh
cost effectiveness	$2,200/ton NO_x removed
10-yr. levelized cost (w/o fuel cost diff.)	1.73 mills/kWh
cost effectiveness (w/o fuel cost diff.)	$600/ton NO_x removed

Baseline NO_x emissions measured at Niles were lower than those found at most cyclone-fired boilers. The primary reason for low baseline NO_x is a low heat input per cyclone compared to most cyclone furnaces; this value is 30% less than the nominal design value for 10-ft cyclones and 22% less than the nominal design heat input for 9-ft cyclones such as Niles.

The long-term test program showed that NO_x could be reduced 55% at full load and 40% at 70% load. Reburning was not used at loads below 70% due to concerns about slagtap freezing. This unit, however, is operated between 50 and 70% load for a significant part of the day (especially in the springtime when the long-term NO_x data were obtained). Measured NO_x results used to calculate the cost effectiveness of reburning at Niles are as follows:

Load, %	Baseline NO_x, lb/mmBtu	NO_x Removed, %
100	0.93	55
70	0.87	40
50	N/A	0

For various load factors, the amount of NO_x removed was calculated as follows:

NO_x removed = (full load NO_x) (% NO_x reduction) (full load heat input) (hours of full load operation) (0.9 availability)

+ (70% load NO_x) (% NO_x reduction) (70% load heat input) (hours of 70% load operation) (0.9 availability)

+ (50% load NO_x) (% NO_x reduction) (50% load heat input) (hours of 50% load operation) (0.9 availability)

Finally, cost effectiveness is the yearly levelized cost of the retrofit divided by the tons of NO_x removed per year.

Reburning cost-effectiveness was much poorer using the Niles load profile. The resulting cost was \$5835 per ton of NO_x removed at a natural gas cost \$1.50/mmBtu higher than coal, and \$1592 per ton of NO_x removed for equal coal and natural gas costs. The high NO_x reduction cost at Niles could be anticipated because it makes no economic sense to install a NO_x control system and then shut it off for more than half of the unit operating time.

Table 16-5 lists estimates of NO_x removal cost effectiveness for Niles and the five study boilers. Different load profiles were assumed for the study boilers, while the actual load profile was used for Niles. The sections that follow detail the methodology used in deriving this table, and discuss each case and the important factors that influence NO_x removal cost effectiveness.

Table 16-5
Summary of Reburning Cost Effectiveness

	Reburning Cost-Effectiveness, \$/T NO_x Removed									
	EPRI TAG		High Load Profile		Niles Load Profile		Typical Load Profile		Intermediate Load Profile	
Unit	Incl. FCD	w/o FCD	Incl. FCD	w/o FCD	Incl. FCD	w/o FCD	Incl. FCD	w/o FCD	Incl. FCD	w/o FCD
Niles	2200	600	N/A	N/A	5835	1592	N/A	N/A	N/A	N/A
Unit A	2069	686	2260	749	4596	1524	N/A	N/A	N/A	N/A
Unit B	2212	567	2011	515	2707	694	2994	767	5229	1340
Unit C	2057	409	1872	373	2520	502	2787	555	4868	970
Unit D	1242	182	1224	179	1889	276	1857	272	3526	516
Unit E	994	121	970	119	1470	180	1471	180	2768	338

Note: FCD = fuel cost differential

NO_x Prediction Methodology

The cost-effectiveness of reburning at Niles No. 1 is based upon the results of long-term testing. Baseline NO_x emissions at various loads as well as controlled NO_x levels were measured directly. Baseline NO_x emissions at Niles, however, are somewhat lower than those reported at many cyclone-fired plants (Maringo, et al. (1987)). The following methodology was used to estimate NO_x emissions for Study Units A through E.

The high NO_x emissions from cyclone boilers result from the high-temperature turbulent combustion process in these units. Peak flame temperatures inside the cyclones and immediately downstream depend on the amount of heat released in the cyclone (under near-adiabatic conditions) and the rate of heat removal downstream of the cyclones. Recall that NO_x formed from nitrogen in the air (thermal NO_x) increases exponentially with increasing temperature and linearly with increasing time at that temperature.

Two boiler design factors and one fuel factor affect thermal NO_x production in cyclone boilers. The boiler design factors are:

1. Heat release in the cyclone
2. Heat removal rate downstream of the cyclones.

Cyclone heat release can be approximated by the cyclone capacity, MW/cyclone. Heat removal rate is qualitatively related to the fraction of cyclones whose exit gases radiate directly to a sidewall. For example, Figure 16-5 shows hypothetical examples of cyclone furnaces where the cyclones are arranged in rows across the firing walls. The gases exiting the outer cyclones radiate heat rapidly to the adjacent sidewall. The gases from the inner cyclones in the third example are, however, somewhat shielded from the sidewalls, thus causing higher temperatures to persist longer in the center of the furnace. In this example, 50% of the cyclones radiate to a sidewall. If the same four cyclones were arranged two over two, as in the first example, all cyclone exit gases would radiate to a sidewall and NO_x emissions would be lower since the gas temperature would be quenched more rapidly. Similarly, opposed-fired boilers, example two, produce slightly higher NO_x than single-wall fired boilers because the hot gases meet and create a hot zone in the middle of the furnace. If the cyclones are offset, NO_x is about the same as one-wall furnace arrangements.

The fuel factor affecting NO_x emissions is fuelbound moisture. Wet fuel depresses flame temperatures and less NO_x is formed. Lignites and most subbituminous coals contain more bound moisture than bituminous coals. Lower NO_x emissions have been measured in cyclone fired boilers that burn low-rank coals.

Table 16-6 shows a comparison of the study units relative to the factors that affect baseline NO_x emissions. How these factors were evaluated in each case study is explained in the sections that follow.

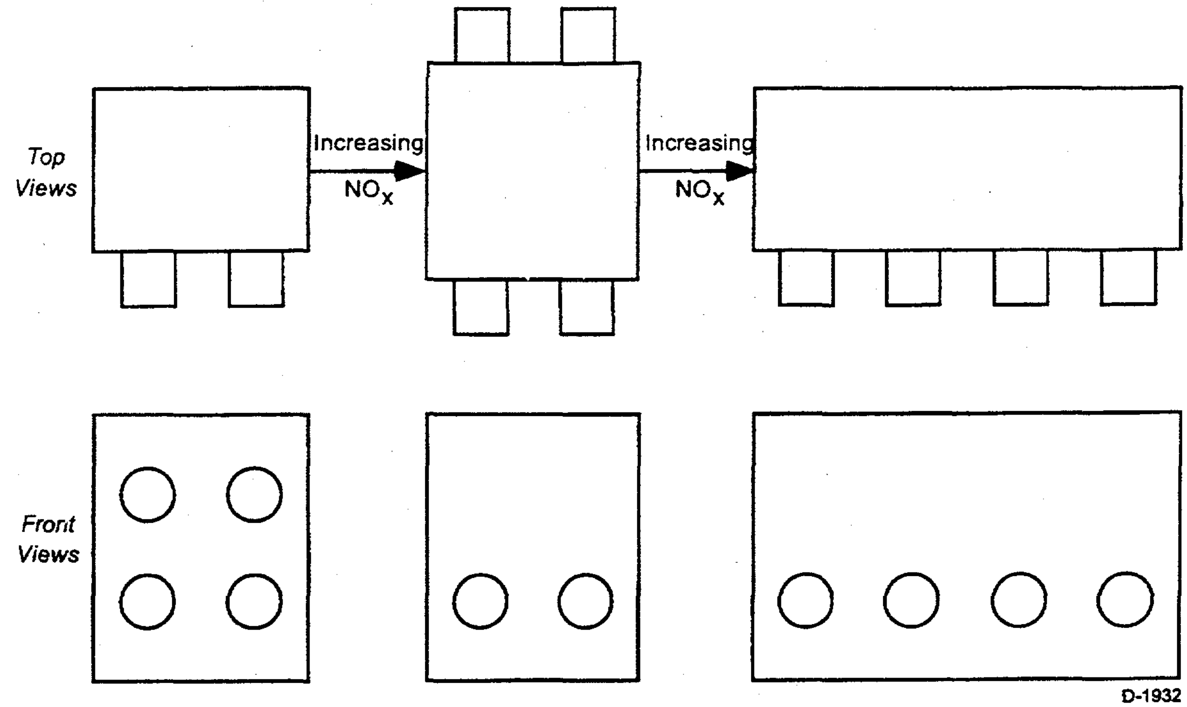


Figure 16-5
Relative Effect of Cyclone Arrangement on NO_x Emissions

The other quantity critical to calculating the NO_x removal cost-effectiveness of reburning is the percent NO_x reduction to be expected. The following assumptions were made regarding NO_x reduction based on reburn process fundamentals:

1. The higher the temperature at the point of reburn fuel injection, the more rapid the NO_x reduction. Thus, the units with higher baseline NO_x should achieve larger percentage NO_x reductions.

Table 16-6
Factors Affecting Baseline NO_x

Unit	No. of Firing Walls	MW/Cyclone	Cyclones Adjacent to a Sidewall, %	Fuel Rank	Est. Full Load NO_x, lb/mmBtu
Niles	1	28.8	100	bituminous	0.93
A	1	37.5	100	subbituminous	1.2
B	1	41.7	67	bituminous	1.4
C	1	45.0	80	bituminous	1.4
D	2 (offset)	52.5	100	subbituminous	1.4
E	2 (opposed)	43.2	57	bituminous	1.7

2. Increased residence time in either the reburn zone or the burnout zone would favorably affect percentage NO_x reduction if temperatures remained constant. At reduced load, residence time increases but gas temperature in the reburn zone decreases. Therefore NO_x removal at reduced load will vary from unit to unit depending upon which factor predominates.

3. The reburn zone stoichiometric ratio (RZS) is 0.90 at full load and 1.0 at minimum reburn load. In between, the RZS varies linearly with load. Further, it is assumed that the percent heat input from natural gas stays constant, and the variation in RZS is caused by a gradual increase in combustion zone excess air.

Assumption 1 indicates that most boilers will achieve higher NO_x reductions than Niles except when residence times are limited. Units A and B had limited residence time available, so their NO_x reduction performance is not expected to be as good as Niles. The long-term tests at Niles were run at a RZS of about 0.94 ± 0.02 over a load range of 70 to 100%. Better NO_x reductions would be expected in newer cyclone boilers where more accurate control of fuel and air flows to each cyclone would allow operation at lower cyclone excess air levels, thus reducing full load RZS to 0.9.

Unit A

Unit A is located in the central part of the United States. It was designed to burn Illinois bituminous coal when it started up in 1969, but recently converted to Powder River Basin subbituminous. The unit produces about 75 MW at full load on either coal. Steam flow is approximately 575,000 lb/h at 1950 psig at the superheater outlet. Steam temperature is 1005 F leaving both the superheater and reheater.

Unit A represents the latest one-wall-fired cyclone design for bituminous coals. Only a few more units were built between 1969 and 1971 when NO_x emission requirements effectively made cyclone boilers obsolete. This unit contains just two cyclones mounted on the front wall. The cyclones are located 12 ft 3 in. apart (centerline to centerline), with a 5 ft 10½ in. clearance between cyclones and the adjacent sidewalls. The main furnace is compact, having a mean bulk gas residence time of only 0.9 s from the cyclone outlet plane to the horizontal plane at the furnace arch.

Figure 16-6 shows Unit A configured for reburning. Like Niles, the reburning fuel injectors are located on the rear wall opposite the cyclones. This arrangement not only maximizes reburning zone residence time, but also should result in good dispersion of reburn fuel since the reburn fuel jets directly oppose the cyclone jets. Five reburn fuel jets located 4 ft apart were chosen to maximize natural gas contact with cyclone exit gas throughout the boiler cross section.

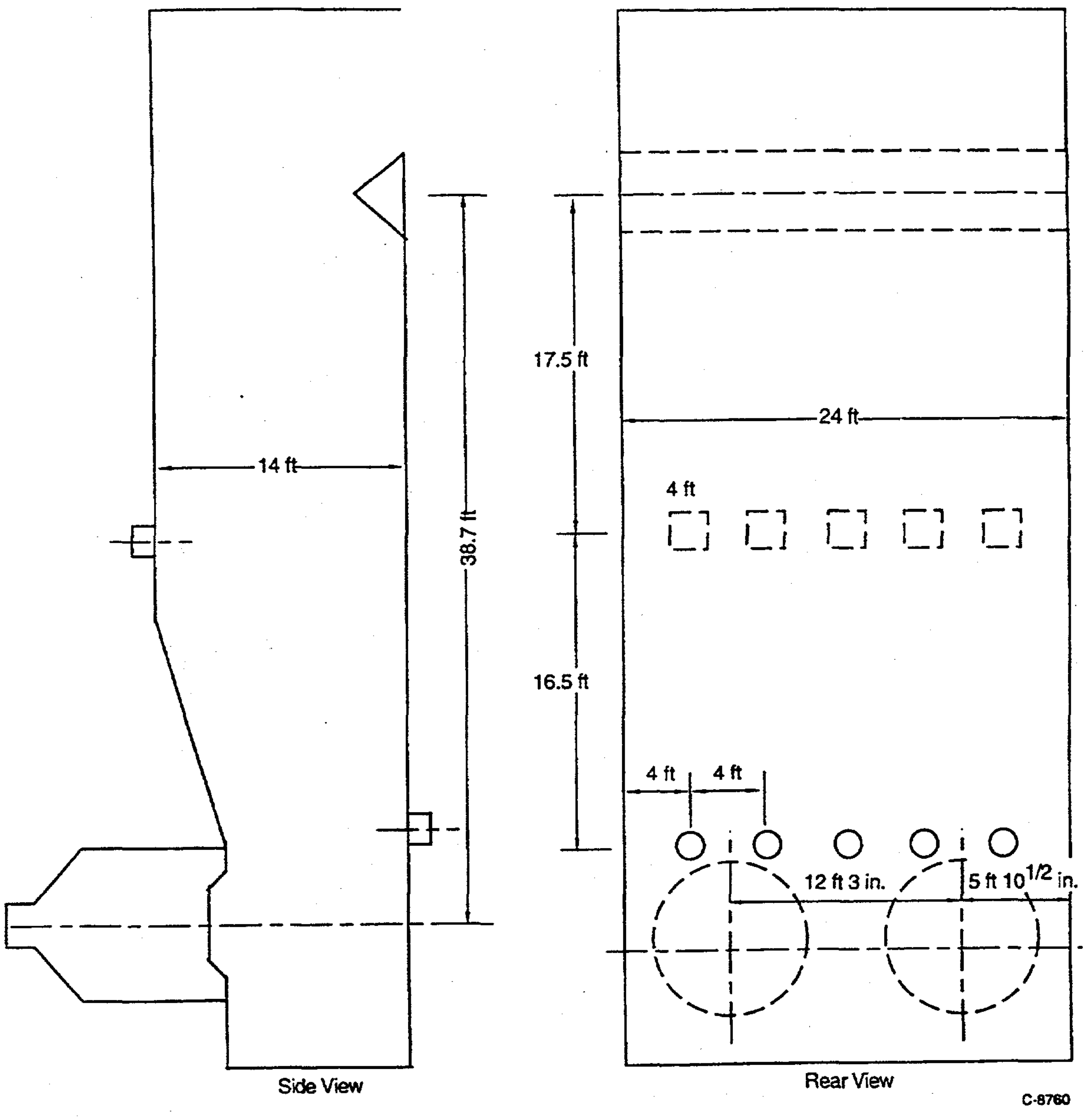


Figure 16-6
Unit A - 75 MW Gross, 1969

The burnout air ports are located on the front wall, 16 ft 6 in. above the reburn fuel injector elevation. This location provides a normalized residence time of 0.77 in the reducing zone and a normalized residence time of 0.88 above the burnout air ports to complete burnout. These residence times are shorter than they were for Niles, but the narrow furnace at Unit A and the closer side spacing of fuel and air injectors should result in faster mixing and similar NO_x performance.

Unit A is expected to produce about 1.2 lb NO_x/mmBtu at full load prior to reburning. The baseline NO_x is higher than Niles because the heat input per cyclone is higher, but not as high as some of the other case boilers due to reduced flame temperature when burning western coals. After reburning is operational, the NO_x emission should be reduced to about 0.45 lb/mmBtu (62.5%). This NO_x reduction is brought about by these factors:

1. The heat input to each cyclone is reduced by 20%, thus reducing peak combustion temperatures and thermal NO_x. The magnitude of this cyclone load reduction on NO_x emission is about 15%.

2. About 20% of the nitrogen-bearing fuel (coal) is replaced with a non-nitrogen-bearing fuel (natural gas).

3. Natural gas reacts with NO to form reactive nitrogen species (like HCN, NH_3) and N_2. The amount of NO destroyed in the reducing zone at a stoichiometric ratio of 0.9 is about 40 to 60% depending on residence time.

4. NO_x can be reformed in the burnout zone by oxidation of reactive nitrogen species escaping the reburn zone. Slow mixing of burnout air and low combustion temperatures minimize NO_x reformation. The NO_x increase in the burnout stage ranges from 0 to 20%.

This NO_x reduction is higher than Niles because the baseline NO_x is higher and because more favorable furnace mixing conditions should result in lower CO emissions at Unit A than at Niles, thus allowing operation at lower reburn zone stoichiometries.

The other question regarding NO_x emission predictions is, can the maximum NO_x reduction be maintained? The full load NO_x reduction during short term tests at Niles ranged from 50% to nearly 70%, depending mostly on the air/fuel balance among cyclones. Since Unit A only has two cyclones and they are equipped with gravimetric coal feeders, NO_x emissions should be more stable and controllable at lower values than they were at Niles. However, NO_x reductions will probably decrease at low load.

Economics of a reburning retrofit at Unit A are summarized below as estimated using the EPRI TAG:

Process Capital	\$2.6M
Total Plant Investment	\$3.0M
Total Capital Required	\$3.1M

Capital Cost per kW	$42	/kW
10-Yr. Levelized Costs	6.9	mills/kWh
Cost Effectiveness	$2069	/ton NO_x removed
Levelized Fuel cost Differential	4.6	mills/kWh
10-Yr. Levelized Cost (w/o fuel Diff.)	2.3	mills/kWh
Cost Effectiveness (w/o fuel cost Diff.)	$686	/ton NO_x removed

It can be seen that the 10-yr. levelized busbar power cost is dominated by the difference between the cost of coal and the cost of natural gas. The first estimate assumes that natural gas escalates to $1.50/mmBtu higher than the cost of coal, certainly a worst-case assumption and a drastic change from today's market. During the time of the Niles demonstration, however, the fuel cost differential paid by the project sponsors was $1.50/mmBtu. The second estimate assumes that coal and natural gas have the same cost, a circumstance enjoyed over the last few years during the summer months in some regions of the country but unlikely to continue in the future. Based on these bracketing assumptions on natural gas price, the cost of reburning on Unit A calculated using EPRI TAG methodology will be $686 to $2069/ton of NO_x removed. The impact of fuel cost differential is plotted in Figure 16-7.

Figure 16-7 also shows NO_x removal cost effectiveness under the load profile scenarios described above. The assumptions used in calculating NO_x removed as a function of load are tabulated below for Unit A:

Load, %	Baseline NO_x, lb/mmBtu	NO_x Removal, %
100	1.2	62.5
70	1.0	50.0
below 67	N/A	0

This plot can be used to estimate the cost of implementing gas reburning for various assumptions of load profile and natural gas cost. Like Niles, Unit A is limited to reburn operation at loads above 67% because slag tapping will be a problem. Therefore, the unit is probably only a viable candidate for reburning if it can be operated at high loads most of the time; and for this reason no cost data are shown on Table 16-5 and Figure 16-7 for Unit A for the typical load profile and the intermediate load profile.

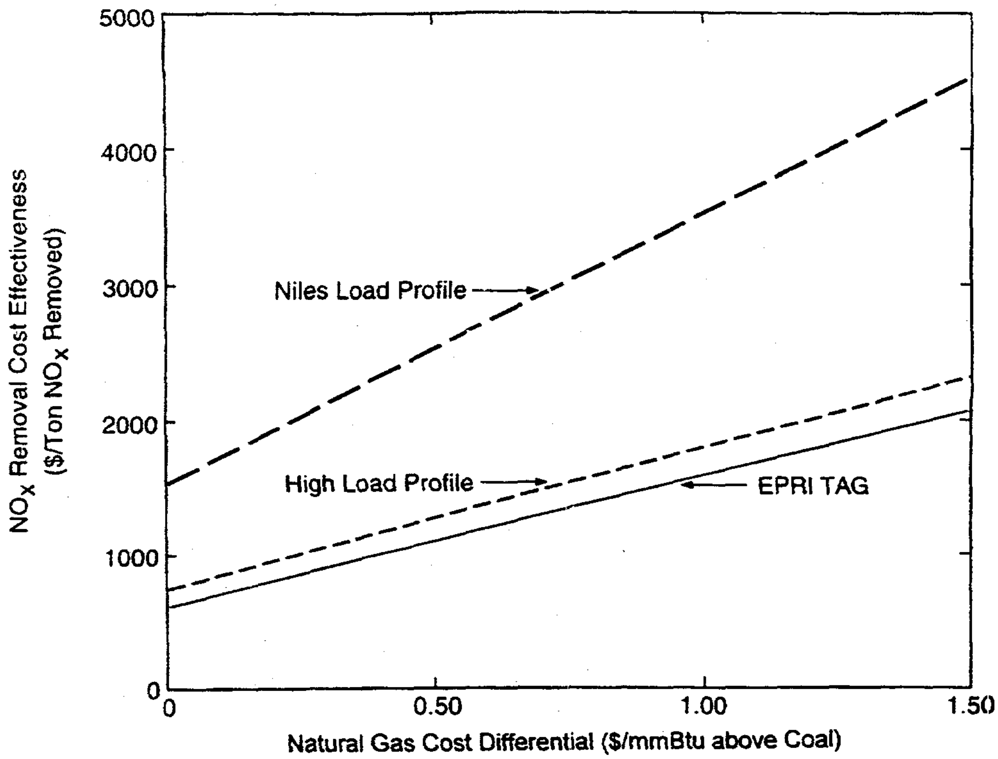


Figure 16-7
Cost of Reburning on a 75 MW Cyclone-fired Boiler

Unit B

Unit B is a 125 MW pressurized boiler located near the Appalachian coal fields. The furnace arrangement is similar to Niles, except more compact. Three cyclone combustors located on the same elevation fire into a primary furnace. Cyclone exit gases are forced downward by the target wall, pass through a bank of screen tubes, and then upward through the main furnace.

Even though Unit B is rated about the same as Niles, the main furnace depth is 2-ft smaller, the width is 1-ft shorter, and the furnace height (cyclone centerline to furnace arch) is almost 20 ft shorter than the Niles unit. As a result, Unit B has much shorter residence times for reburning and burnout compared to Niles or most other cyclone units.

Unit B was started up in 1957, four years later than Niles. It produced 675,000 lb/h of steam at a superheater outlet pressure of 4550 psig and temperature of 1150 F. This unit was decommissioned in the mid-1980s due to higher operating and maintenance costs compared to other units in its system.

Certainly Unit B represents the most difficult case for cyclone-fired boiler reburning.
Figure 16-8 shows a general arrangement sketch of the unit, including potential fuel and air injector locations. Five reburning fuel injectors are located on the rear wall opposite the cyclone

combustors. The reburn fuel injectors are spaced 5-ft 8-in. apart horizontally and tilted downward to maximize residence time in the reducing zone. Burnout air ports are located on the sidewalls 13-ft above the reburn fuel injectors. Sidewall air ports were chosen because, like Niles, Unit B is likely to have no access for air duct work at this elevation on the front or rear walls.

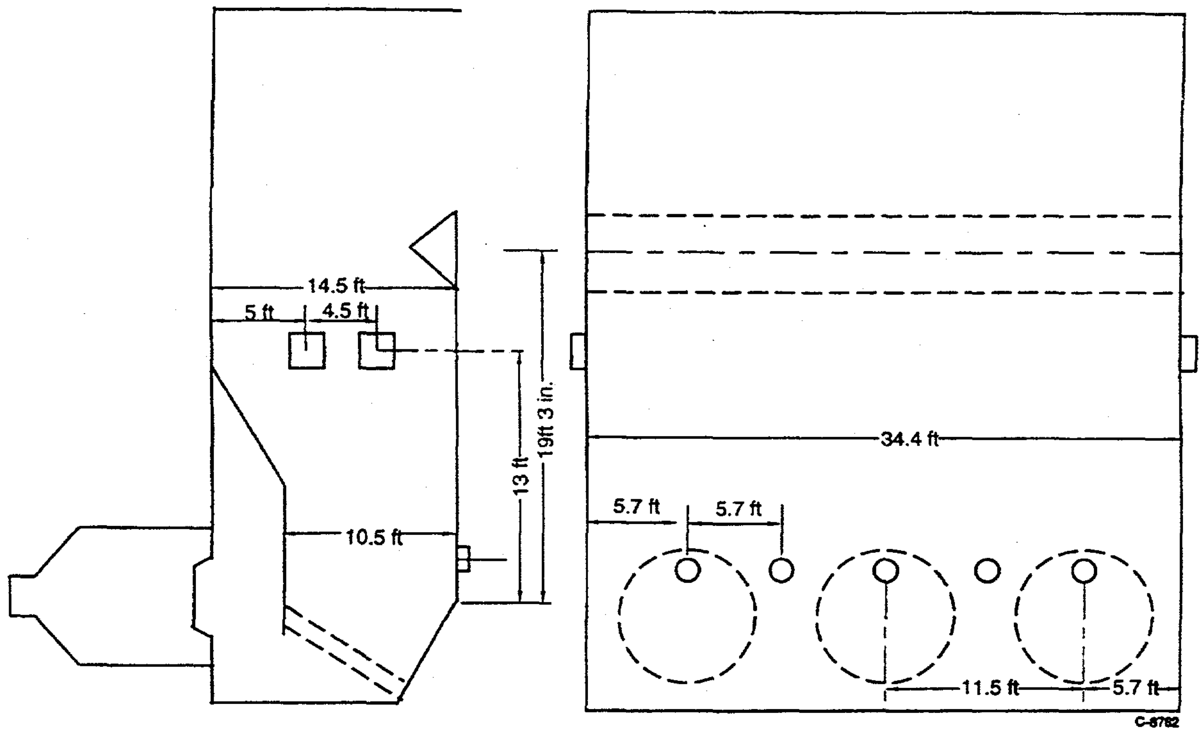


Figure 16-8
Unit B - 125 MW Gross, 1957

These reburn fuel injector locations provide normalized reburning zone mean bulk-gas residence time of 0.46. Normalized burnout zone time is 0.39. Both these residence times are less than optimal for NO_x reduction and carbon burnout. NO_x reductions of only 40 to 50% are expected at full load from Unit B.

Unit B baseline NO_x at full load is about 1.4 lb/mmBtu. Full load NO_x reductions are assumed to be limited to 45% due to residence time constraints in this boiler. At partial loads (50 to 70%), NO_x reductions could increase slightly due to additional residence time available for mixing. Both NO_x destruction and carbon burnout times will increase at low loads. Longer burnout time may further reduce NO_x emissions by allowing operation at lower cyclone excess air levels without worrying about increased unburned carbon in the flyash.

Assumptions for NO_x reduction versus load are tabulated below for Unit B.

Load, %	Baseline NO_x, lb/mmBtu	NO_x Removal, %
100	1.4	45
70	1.2	50
50	1.0	50
below 44	N/A	0

Economics of a reburning retrofit at Unit B are summarized below:

Process Capital	\$3.22M
Total Plant Investment	\$3.70M
Total Capital Required	\$3.91M
Capital Cost per kW	\$31.3 /kW
10-Yr. Levelized Costs	6.20 mills/kWh
Cost Effectiveness	\$2212 /ton NO_x
10-Yr. Levelized Cost (w/o fuel cost Diff.)	1.59 mills/kWh
Cost Effectiveness (w/o fuel cost Diff.)	\$567 /ton NO_x removed

Figure 16-9 shows the NO_x removal cost effectiveness for this unit over a range of natural gas - coal price differentials and load profile scenarios. Even with less effective reburning, the cost effectiveness of Unit B is comparable to that of Unit A at high load, and more flexibility exists for achieving NO_x reductions at low load.

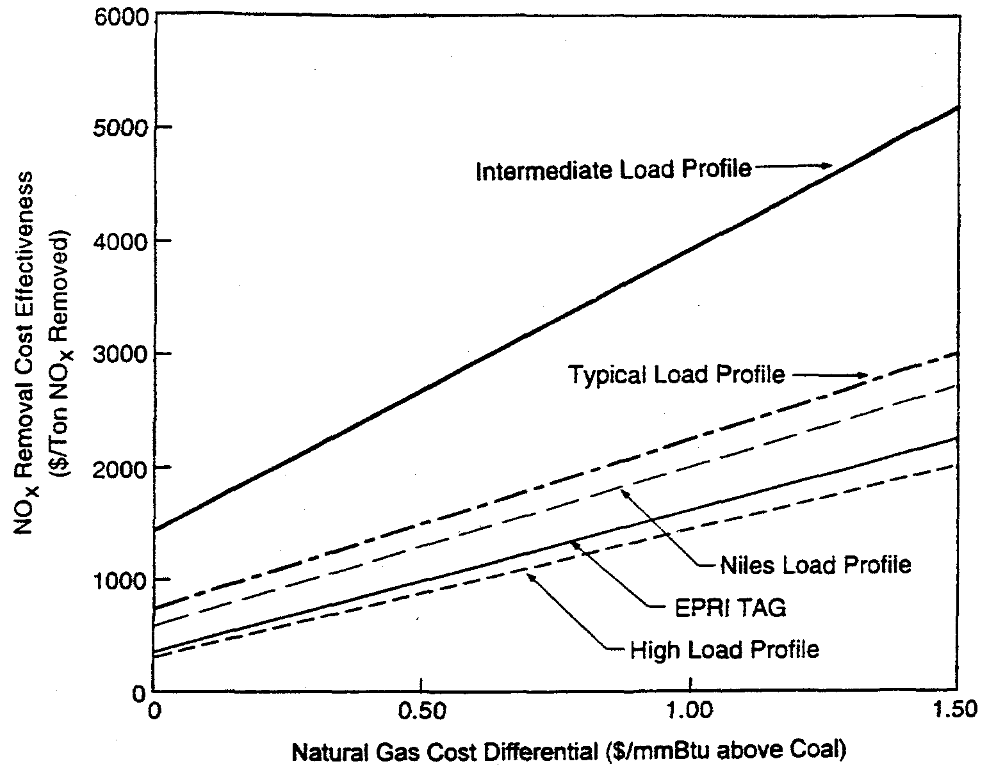


Figure 16-9
Cost of Reburning on a 125 MW Cyclone-fired Boiler

Unit C

Unit C is a one-wall-fired cyclone boiler rated at 225 gross MW. It is located in the midwest and first started up in 1958. Two elevations of cyclone combustors, arranged two over three, fire bituminous coal. Slag is captured in a primary furnace, and the products of combustion pass through a slag screen and into the main furnace where reburning takes place. Figure 16-10 shows a general arrangement sketch of Unit C with reburning applied.

The reburning fuel injectors are located on the rear wall of the main furnace and tilted downward to maximize reburning fuel mixing rate and residence time for NO_x reduction reactions. There are seven injectors spaced 6 ft apart to cover the entire boiler width. Burnout air ports are located on the furnace sidewalls 13.5 ft above the reburn fuel injectors. Two air ports on each sidewall are spaced about 5-1/2 ft apart. A potential problem with this layout is that burnout air must penetrate and mix within a 48-ft boiler width. This distance is 14 ft larger than the boiler width at Niles, thus increasing the risk of unburned combustibles in the flue gases. Unit C is another very difficult retrofit candidate.

The costs of reburning calculated from the EPRI TAG and applied to Unit C are summarized below:

Process Capital	\$4.50M
Total Plant Investment	\$5.18M
Total Capital Required	\$5.45M
Capital Cost per kW	\$24.2 /kW
10-Yr. Levelized Costs	5.76 mills/kWh
Cost Effectiveness	\$2057 /ton NO_x removed
10-Yr. Levelized Cost (w/o fuel Diff.)	1.14 mills/kWh
Cost Effectiveness (w/o fuel cost Diff.)	\$409 /ton NO_x

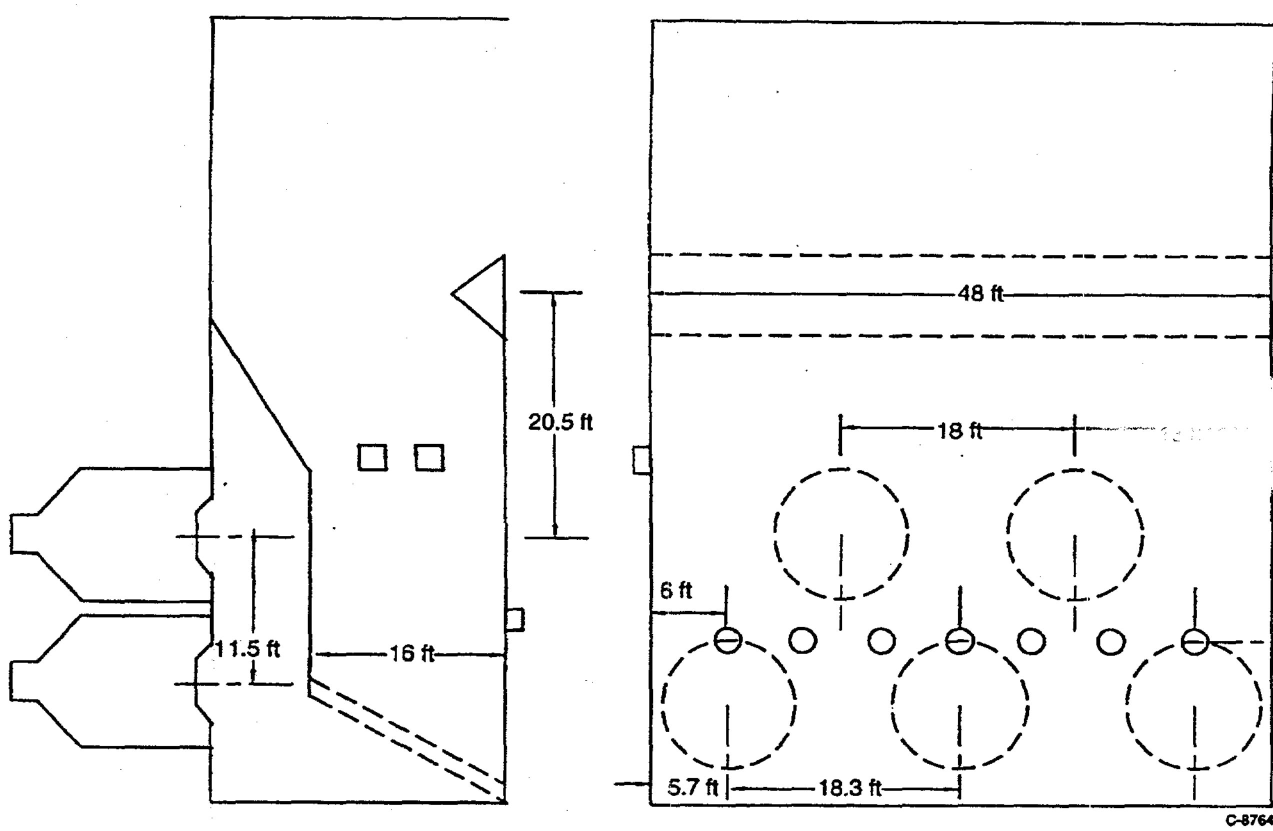


Figure 16-10
Unit C - 225 MW Gross, 1958

Full load NO_x emissions are estimated at 1.4 lb/mmBtu for Unit C. The heat input per cyclone is within design limits for 10-ft cyclones and the exit gas from four out of five cyclones is cooled by boiler sidewalls. Both these factors are similar to Unit B, indicating that full load NO_x should also be similar.

Unit C is also expected to achieve better NO_x reductions with reburning at partial load. Given the cyclone configuration, minimum load of about 30% is achievable for short periods of time with the lower three cyclones operating at about half their design heat input. Assumptions used for calculating NO_x removal as a function of load are tabulated below:

Load, %	Baseline NO_x, lb/mmBtu	NO_x Removal, %
100	1.4	45
70	1.2	50
50	1.0	50
below 40	N/A	0

Some economies of scale are realized since Unit C has double the megawatt production of Niles, but inferior NO_x reduction potential makes Unit C a less attractive candidate for gas reburning. Figure 16-11 shows how reburning cost effectiveness for Unit C would be affected by natural gas prices. The range of \$409 to \$2057/ton of NO_x removed is comparable to Niles and Units A and B using the EPRI TAG. Much better cost effectiveness is achieved for Unit C when applying any of the load-following scenarios due to its ability to use reburning down as low as 40 percent load.

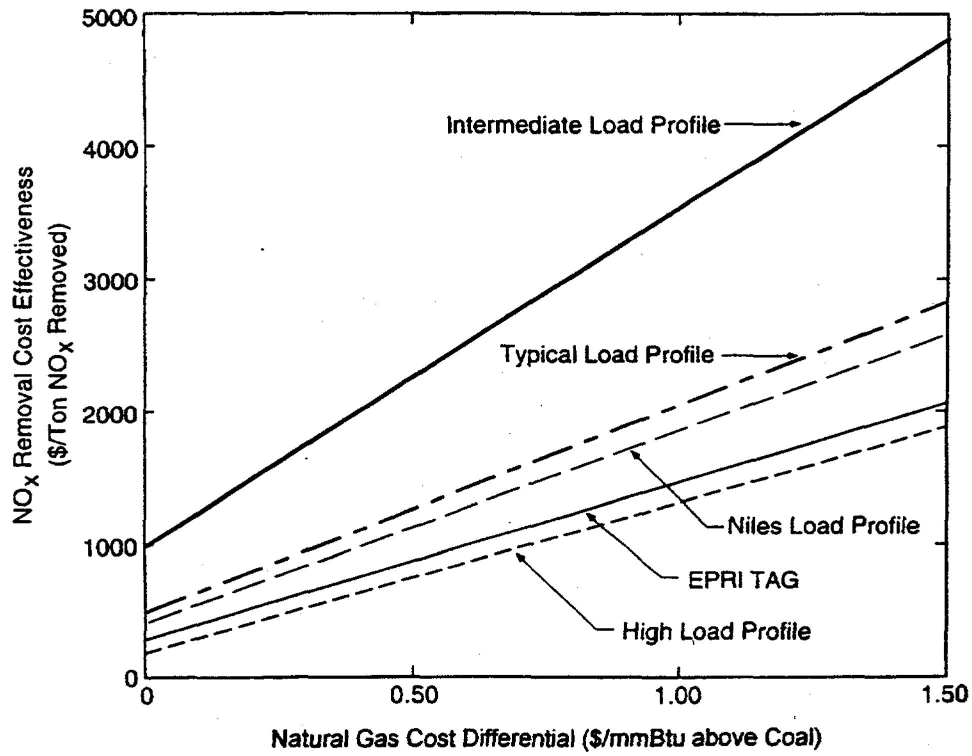


Figure 16-11
Cost of Reburning on a 225 MW Cyclone-fired Boiler

Unit D

Unit D is a modern cyclone boiler, having started up in 1968. It is located in the midwest and designed to fire Illinois bituminous coals. It has been switched to low-sulfur Powder River Basin subbituminous coal recently to comply with Title IV of the Clean Air Act Amendments.

Unit D is a supercritical unit rated at 420 gross MW. Design steam temperatures are 1005 F for both superheated and reheated steam at a superheater outlet pressure of 3810 psig. This unit is fired by eight cyclones arranged two over two on opposed walls as shown in Figure 16-12. The cyclones are staggered so that no two combustors are directly opposed. Cyclone horizontal spacing is 15 ft (centerline to centerline) while vertical spacing is 17 ft.

The products of combustion pass from the cyclones into an open furnace where most of the steam production occurs. Most open furnaces are wider than they are deep (in this case 36 ft wide by 27 ft deep), and have ample volume available within which reburning can take place. To apply reburning, natural gas injectors would be located on the front and rear walls at an elevation 11 ft above the upper cyclone centerline. Each wall would contain six injectors spaced about 5 ft apart to assure rapid mixing of reburning fuel with cyclone exhaust gas. The burnout air ports would be located 40 ft above the reburn fuel injectors. The normalized mean bulk gas residence time for NO_x reduction would be 0.95. The 39 ft. between the burnout air ports and the furnace arch would provide adequate residence time for burnout of the reburn fuel and any unburned coal. The air ports would be located 6 ft apart horizontally to assure complete mixing well before the furnace exit plane.

Reburning should be effective in reducing NO_x by 70% at full load in Unit D (from a baseline of 1.4 lb/mmBtu to 0.4 lb/mmBTU) because all the design criteria listed on Table 16-3 are met, and because the unit has gravimetric coal feeders that can help balance cyclone air/fuel ratios at minimum excess air levels. The economics of the retrofit are summarized below as calculated using the EPRI TAG:

Process Capital	\$6.15M
Total Plant Investment	\$7.08M
Total Capital Required	\$7.46M
Capital Cost per kW	\$17.8 /kW
10-Yr. Levelized Costs	5.41 mills/kWh
Cost Effectiveness	\$1242 /ton NO_x removed
10-Yr. Levelized Cost (w/o fuel Diff.)	0.79 mills/kWh
Cost Effectiveness (w/o fuel cost Diff.)	\$182 /ton NO_x

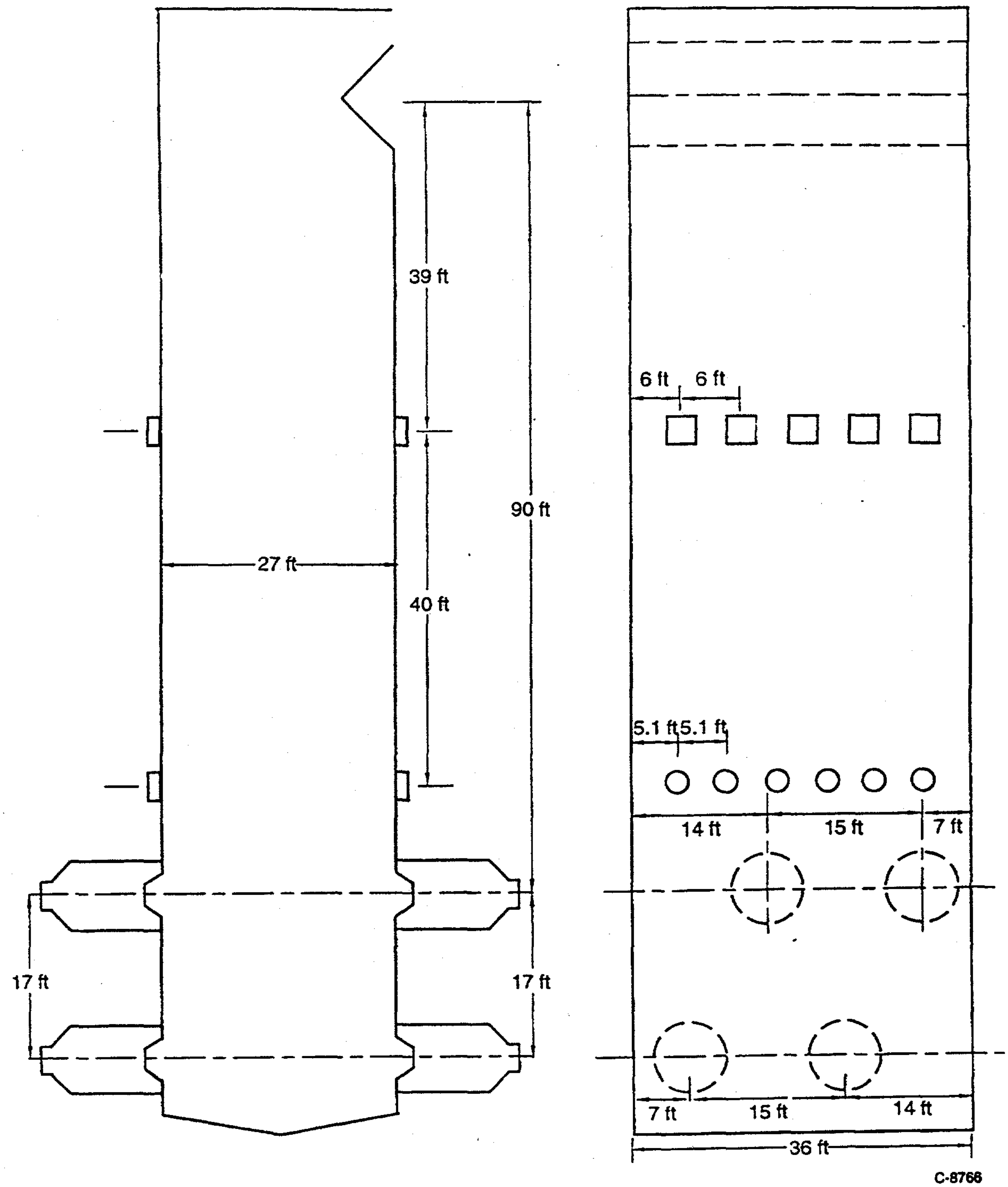


Figure 16-12
Unit D - 420 MW Gross, 1968

Unit D has significantly higher energy input per cyclone than units B, C, and E. Higher cyclone heat input usually means higher baseline NO_x emissions. However, the staggered cyclone arrangement, where the gases leaving each cyclone radiate to the main furnace sidewalls, will result in relatively low peak temperatures in the main furnace and lower NO_x formation downstream of the cyclone furnaces. Therefore, baseline NO_x similar to Units B and C is predicted. Assumptions used to calculate NO_x removal effectiveness for different load profiles are listed below:

Load, %	Baseline NO_x, lb/mmBtu	NO_x Removal, %
100	1.4	70
70	1.2	60
50	1.0	50
below 38	N/A	0

Minimum load for Unit D is about 105 MW for short term operation. This load is achievable with only the lower four cyclones in service firing at about half load. The higher-than-normal full load heat input is another advantage for this unit since the potential cyclone turndown could be even more than 50% without freezing the slag layer in the combustor. Therefore, minimum load with reburning may be as low as 160 MW with a reasonable safety margin for slag tapping.

The dependency of cost effectiveness on natural gas price differential and load profile for Unit D is shown in Figure 16-13. As expected, reburning is much more cost-effective for larger boilers. In addition, load profile is not quite as important as the cost effectiveness lines merge into 3 categories: high, typical, and intermediate.

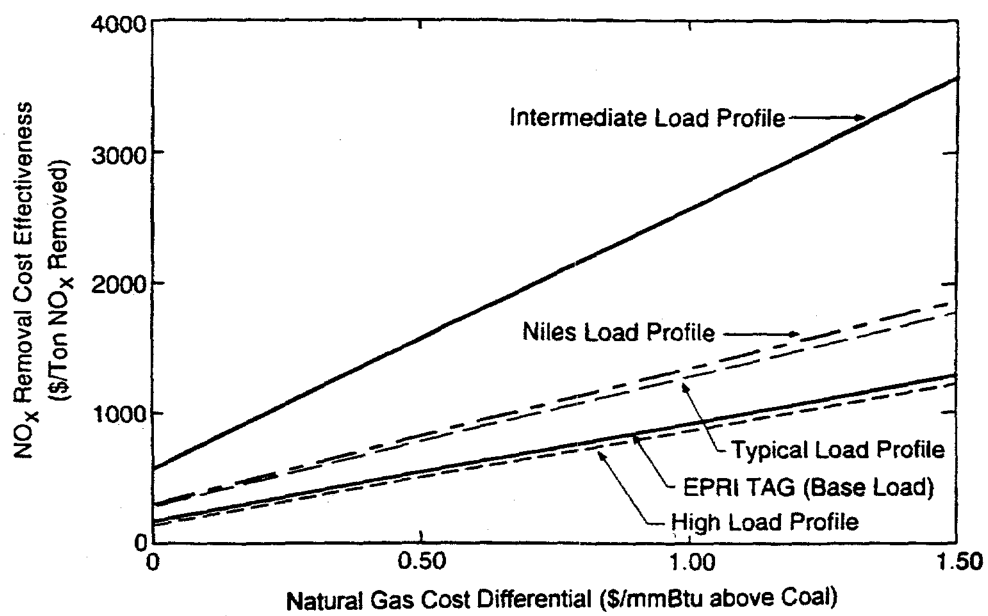


Figure 16-13
Cost of Reburning on a 420 MW Cyclone-fired Boiler

Unit E

Unit E is a 605 MW, once-through boiler located in the midwest. Started up in 1970, Unit E burns Illinois bituminous coals as well as small amounts of waste fuels. Steam conditions are 1005 F superheat and reheat at a superheater outlet pressure of 2620 psig.

Figure 16-14 shows a sketch of Unit E retrofitted with natural gas reburning. The unit contains 14 cyclone furnaces, 7 mounted on the front and rear wall in a three-over-four array. The main furnace is 60-ft wide by 33-ft deep. Cyclone spacing is about 15-ft horizontally (see Figure 16-14 for detailed dimensions) and 17-ft vertically.

The reburn fuel injectors would be located on the front and rear walls about 15 ft above the centerline of the top row of cyclones. Each wall would contain seven injectors spaced 8 ft apart. The burnout air ports would be located 36 ft above the reburn fuel injectors, providing a mean bulk-gas normalized residence time in the reburning zone of 1.18. Burnout air port side spacings would be identical to those for the fuel injectors. There would still be 66 vertical ft from the air ports to the furnace arch, providing a normalized mean, bulk-gas residence time for burnout of 1.72.

Baseline NO_x for Unit E is expected to be around 1.7 lb/mmBtu at full load. The main factor contributing to higher baseline NO_x for this unit is the close packing of cyclone combustors in the main furnace leading to high peak temperatures. These same high temperatures, however, should help reburning effectiveness by increasing the rate of NO_x destruction. Natural gas reburning should be able to achieve a 70% NO_x reduction down to 0.5 lb/mmBtu. The economics as calculated by the EPRI TAG method for this retrofit are summarized below:

Process Capital	\$7.39M
Total Plant Investment	\$8.49M
Total Capital Required	\$8.97M
Capital Cost per kW	\$14.83 /kW
10-Yr. Levelized Costs	5.26 mills/kWh
Cost Effectiveness	\$994 /ton NO_x
10-Yr. Levelized Cost (w/o fuel Diff.)	0.64 mills/kWh
Cost Effectiveness (w/o fuel cost Diff.)	\$121 /ton NO_x removed

The assumptions used to calculate the NO_x removal effectiveness for Unit E at different load profiles are listed below:

Load, %	Baseline NO_x, lb/mmBtu	NO_x Removal, %
100	1.7	70
70	1.5	60
50	1.3	50
below 49	N/A	0

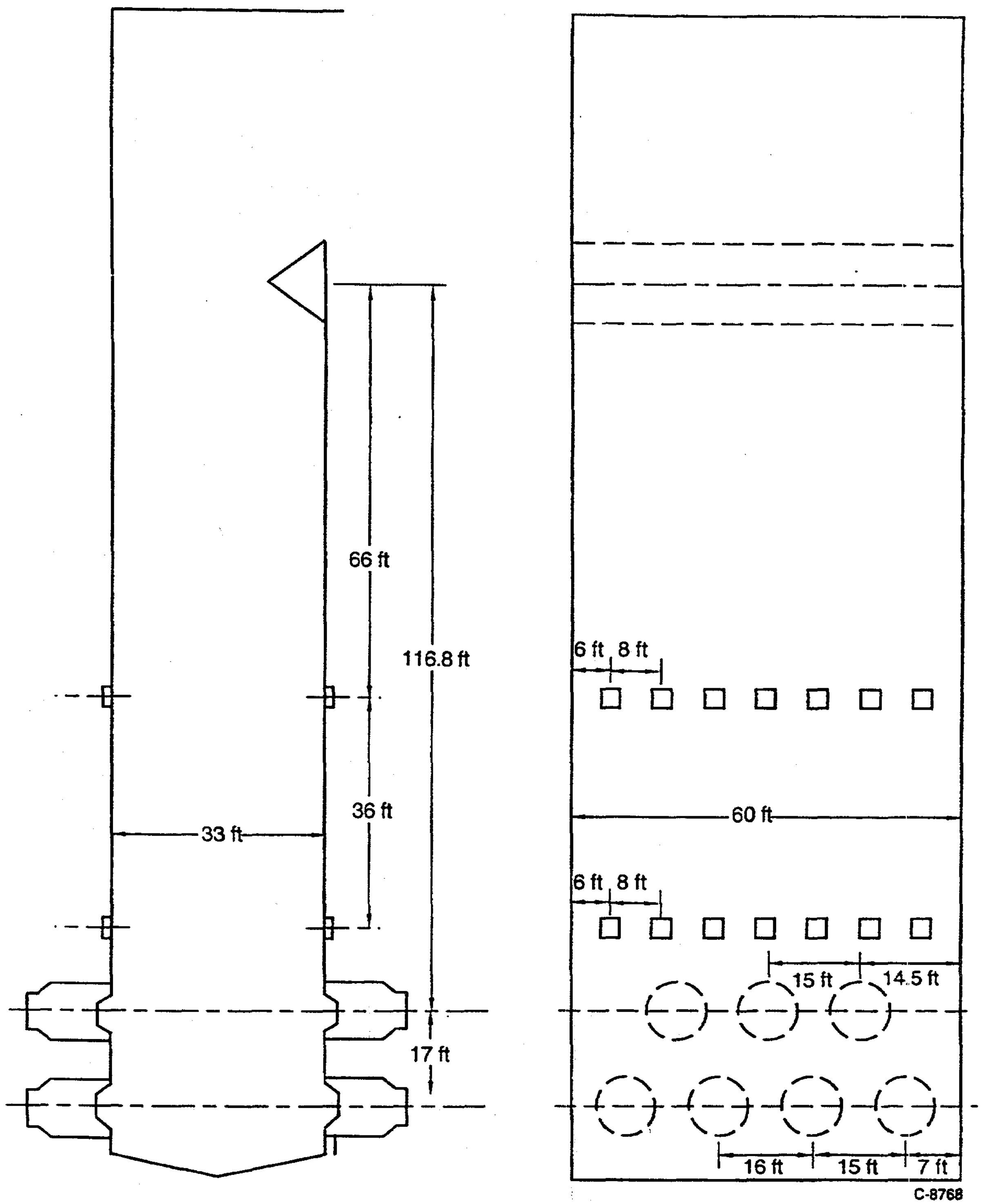


Figure 16-14
Unit E - 605 MW Gross, 1970

Minimum load of 175 MW for this unit is achievable with the eight lower cyclones operating at half load. When reburning is added, each cyclone is derated by about 20% as heat input is transferred to the reburn gas injectors. Leaving a margin of safety, reburning is limited to loads above 300 MW (49% of rated capacity). NO_x removal efficiency will gradually decrease with load as main furnace temperature decreases and cyclone outlet O_2 increases.

Figure 16-15 summarizes the NO_x removal cost effectiveness for Unit E. This unit appears to be a good candidate for reburning regardless of how coal and gas prices fluctuate over the next decade.

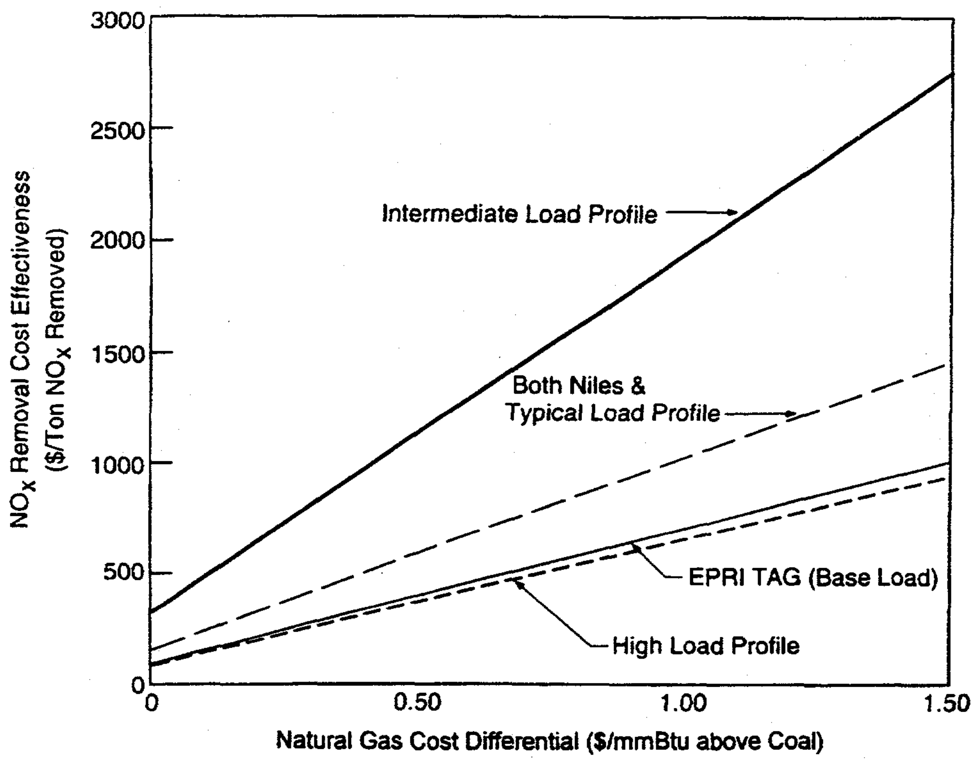


Figure 16-15
Cost of Reburning on a 605-MW Cyclone-fired Boiler

Other Reburning Systems

Natural gas reburning has been applied by others to three other boilers in the United States (Hong et al. (1993) and May et al. (1994)). These boilers are listed in Table 16-7. All three projects are demonstrations funded partially by the U.S. Department of Energy under the Clean Coal Technologies Program and by the Gas Research Institute.

Table 16-7
Other Boilers Retrofitted with Natural Gas Reburning

Illinois Power	Hennepin Station Unit #1	Tangential	71 MW (g)
Public Service Company of Colorado	Cherokee Station Unit #3	One-wall fired	172 MW (g)
City of Springfield, IL	Lakeside Plant Unit #7	Cyclone	33 MW (g)

Recently capital cost data have been published for two of these units, Hennepin and Lakeside, Swanekamp (1995). The installed capital cost at Hennepin was $38/kW while Lakeside came in at $60/kW. EPRI TAG methodology was used in both cases.

Reburning performance has also been documented during long-term operation at both these plants, May et al. (1994). Performance data are summarized in Table 16-8.

Table 16-8
Long-term Reburning Performance in Other Boilers

Performance Parameter	Hennepin	Lakeside
Load range	25 to 72 MW	23 to 34 MW
Average baseline NO_x	0.75 lb/mmBtu	1.0 lb/mmBtu
Average controlled NO_x	0.25 lb/mmBtu	0.34 lb/mmBtu
Range of daily NO average	0.18 to 0.32 lb/mmBtu	0.21 to 0.47 lb/mmBtu
Percent reburn fuel (Btu basis)	10 to 18%	20 to 26%

It can be seen that performance of these units was comparable to Niles.

Cost Summary

Figure 16-16 shows a comparison of the capital costs of reburning for the five study boilers. Two other boilers (Hennepin and Lakeside) are also included in the comparison based on published cost information. This figure shows that gas reburning is best justified on larger baseloaded boilers. Further, the Hennepin and Lakeside data points lend credibility to the cost escalation methodology employed in this study.

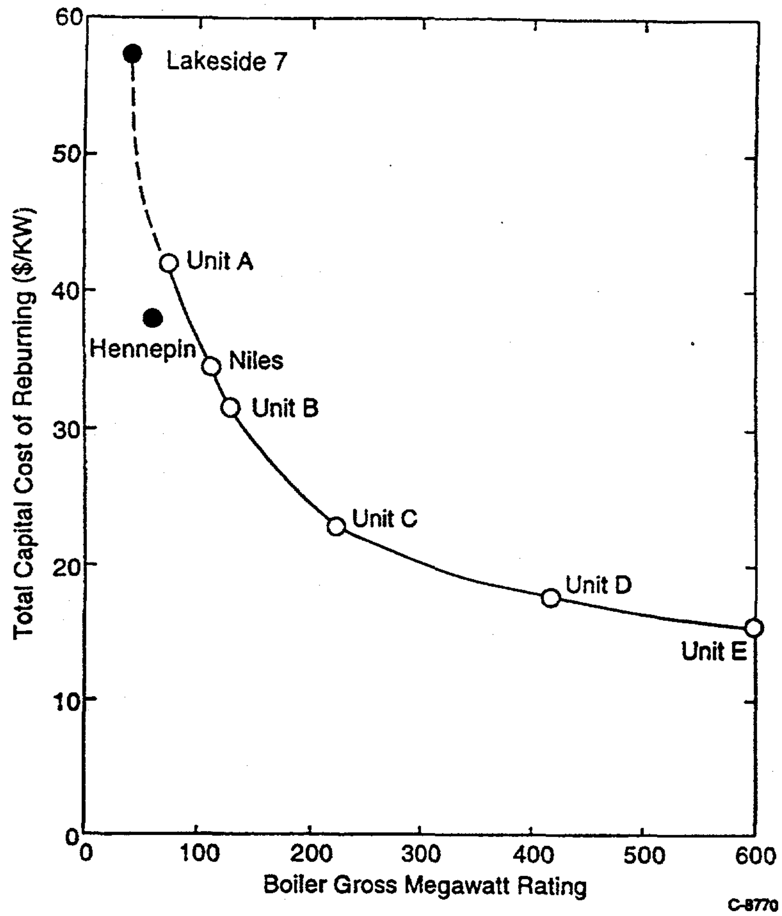


Figure 16-16
Capital Cost of Natural Gas Reburning

Figure 16-17 shows the cost-effectiveness of reburning for Niles and the study boilers using the Niles load profile. Although boiler size has a significant effect on reburning cost effectiveness (due to both larger NO_x reductions and economics of scale), the driver for implementation of natural gas reburning will be the cost of natural gas. As long as natural gas prices stay close to the prices of coal, natural gas reburning will be an attractive option for cyclone boiler NO_x control.

Smaller cyclone boilers (those having four or fewer combustors) can also be limited to reburning operation at 70 percent load or above. Many of these units like Niles are dispatched according to system demands and subsequently operate at minimum load for much of the offpeak demand periods. As Figure 16-17 shows, NO_x removal costs increase sharply for Niles and Unit A at the load profile typical of Niles. The larger the unit, the more flexibility the unit may have for low-load operation with reburning so that the technology becomes less dependent on load profile.

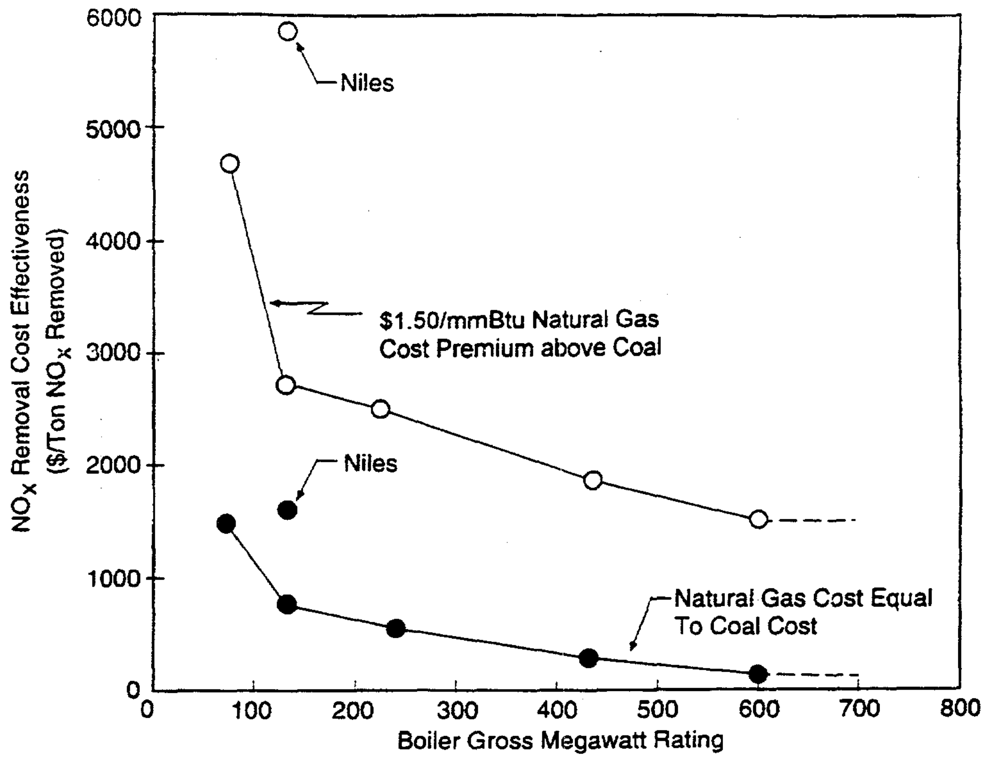


Figure 16-17
NO_x Removal Cost Effectivenesses for a Range of Boiler Sizes Based on the Niles Load Profile

Conclusions

A representative sampling of the cyclone boiler population has been evaluated for the feasibility of retrofitting natural gas reburning. Using design criteria from the Niles demonstration, virtually all cyclone units can be retrofitted. Reburning NO_x reduction, however, will range from 40 to about 70%, depending on the residence time available in the main furnace and the load profile of the unit. Larger open-furnace designs will provide more residence time and thus achieve greater NO_x removal than smaller, primary-furnace designs. Base loaded plants will achieve greater NO_x removal since cyclone furnace turndown may limit how much natural gas can be used at low load.

It was also found that cyclone boilers have shallower furnaces (less depth front-to-back) than other types of boilers. The largest cyclone-fired units (TVA, Paradise #3 et al.) are only 33 ft deep. The implication of this observation is that flue gas recirculation is not required to help disperse the reburning fuel on any cyclone-fired boiler.

In summary, nearly all cyclone boilers can be retrofitted with gas reburning, but small furnaces may limit the effectiveness of reburning in early boiler designs (1950's). The age and expected lifetime of some cyclone units may make selective non-catalytic reduction processes (less capital-intensive processes) better choices for NO_x control in these older units. Reburning seems most attractive for larger cyclone units built in the 1960's and 1970's (lignite-fired). The cost of natural gas will be the most important single factor in determining the number of cyclone boilers that can economically use reburning to meet future NO_x regulations.

Table 16-5, shown above, summarizes reburning cost-effectiveness for all boilers and load profiles, with and without a \$1.50/mmBtu fuel cost differential between natural gas and coal. For smaller boilers such as Niles or Units A and B, low load operating limits make reburning economically unattractive. Even for larger cyclone units, intermediate load operation will increase the NO_x removal cost by a factor of three. However, since most cyclone boilers were designed for and are best suited for base loaded operation, reburning is a good choice. Moreover, for utility systems subjected to environmental dispatch, reburning may in fact allow higher load factors to be utilized in cyclone units. Each utility must weigh the technical and economic merits of the technology for their own unique situation. It is the intent of Section 16 to provide enough information to allow an intelligent first cut at the natural gas reburning choice for all cyclone boiler owners.

17

CONCLUSIONS AND RECOMMENDATIONS

A natural gas reburn system was installed on Ohio Edison's Niles Unit No. 1, a 115 MW (gross) cyclone-fired boiler. The objective was to demonstrate that 50% NO_x reduction could be achieved at full load and that the reburn system could be operated without adversely affecting boiler thermal performance and component life.

The project at the Niles plant represented the first commercial demonstration of a natural gas reburn system. Although the effectiveness of reburning as a NO_x reduction technique has been shown in many laboratory and pilot scale experimental tests, the subject demonstration was the first to look at the total impact of a reburn system in a commercial boiler. Though NO_x reduction was the focus of the demonstration, it was even more important that the reburn system not cause any unacceptable side effects on boiler operation and component life. Indeed, execution of this project turned up a few unexpected results illustrating just why R&D demonstrations are conducted. It is believed that results from this project were valuable in their own right and, furthermore, that lessons learned here provided very useful input and direction to those who would conduct follow-on demonstrations of reburn systems.

The original reburn system was designed to employ flue gas recirculation (FGR) as a carrier gas for better mixing of the natural gas with the bulk flue gas in the reburn zone. Project objectives were met with the original system relative to NO_x reduction and boiler thermal performance. However, much thicker slag deposits formed on the back wall, the one in which the reburn fuel injectors were installed, compared to the base case deposits. The thicker deposits were found to be caused by the relatively cooler FGR near the affected wall. The deposits, which were as much as 12 inches thick (compared to the normal 2 to 4 inches), had little or no effect on boiler performance and did not prevent completion of the original system test program. However, long-term operation of the original reburn system was unacceptable for several reasons. Slag falls during boiler operation could have a damaging effect on screen tubes at the bottom of the furnace; the possibility of slag falls during slag removal operation was a risk to personnel; and slag accumulation could cause blockage and misdirection of the reburn fuel jets as well as shortened life of the nozzles due to overheating. For these reasons there was a need to identify the cause of the problem and to resolve it.

Resolution of the slag buildup problem led to the development of the modified reburn system. In the modified reburn system FGR was eliminated. Deposits on the back wall returned to normal thickness. NO_x reduction was initially lower than with the original system; but with continued operation and increased operator familiarity, NO_x reduction improved and during the last period of long-term testing full load NO_x reduction was greater than that achieved with the original system. Importantly, there were a number of other advantages with the modified system both operational and economic: the modified system showed heat transfer distribution within the boiler to be much closer to the base case conditions, and the cost of the reburn system was lower due to the elimination of the FGR and associated equipment. The plant net heat rate was also improved by eliminating the power requirement for the gas recirculation fan.

Long-term testing was carried out with the modified system under normal economic dispatch conditions during a period of three and one-half months.

The following provides a summary of the most important observations and conclusions reached during this demonstration project:

- Natural gas reburn significantly reduced NO_x emissions from the Niles Unit No. 1 cyclone fired furnace. Reburn also affected CO emissions. Specific NO_x and CO emissions behavior was observed as follows:

  - NO_x reductions of 30 to 70% were measured during parametric testing of the original system at full load.
  - NO_x reduction of up to 55% was demonstrated at full load with acceptable boiler operation and CO emission lower than 100 ppm using the modified reburn system.
  - NO_x reduction of 66.8% was demonstrated at full load with acceptable boiler operation and CO emission of 1514 ppm using the modified reburn system.
  - Reburn zone stoichiometry (RZS) was the most significant operating variable affecting NO_x reduction by the reburn process.
  - NO_x emissions decreased linearly as RZS was decreased.
  - CO emissions increased exponentially when RZS was decreased.
  - For long-term operation of a commercial reburn system RZS should be maintained slightly above 0.9 to simultaneously minimize both NO_x and CO. Because of the inability to maintain precise coal/air ratios in each of the cyclones at Niles No. 1 during long-term testing, simultaneous NO_x and CO emissions were minimized at RZS of 0.94.

- Natural gas reburn had a minimal effect upon boiler performance and electrostatic precipitator (ESP) performance.

  - During 18% natural gas reburn testing with the original system, waterwall heat absorption decreased by approximately 5%; attemperator spray flows, operating in a normal range, were able to control steam temperatures at the design levels.
  - Boiler efficiency decreased by 0.6% with 18% natural gas reburning in the original system due principally to higher latent heat of vaporization losses caused by greater moisture formation from natural gas.

- ESP collection efficiency was lowered slightly during reburn system operation due to lower ESP inlet loading and a non-optimized flue gas conditioning system.

- Operation of the original reburn system led to the buildup of much thicker ash deposits on the rear wall of the furnace at Niles No. 1.

  - Long term operation of the reburn system could not be sustained with the original reburn system due to abnormally heavy slag buildup on the back wall and over the reburn fuel injectors.
  - The primary cause of thicker ash deposits was the cooling effect of FGR on the rear wall.
  - The cooler FGR caused the normally thin, molten deposits to become thicker, sintered deposits as they equilibrated to the change in the thermal environment.

- The original reburn system was replaced by a modified reburn system in which the FGR system was eliminated. Eliminating FGR eliminated the ash buildup problem. The modified reburn system also provided several cost and operations advantages over the original reburn system.

  - Lower capital cost.
  - Smaller space requirement.
  - Elimination of the high maintenance, energy intensive FGR fan.
  - More favorable furnace heat absorption distribution. Radiant section heat absorption increased and convective section heat absorption decreased resulting in lower attemperator water flow requirement. Boiler efficiency was essentially the same as that of the original system.

- The modified reburn system, initially showed a NO_x removal efficiency about 8% lower than the original reburn system. Possible causes for the lower NO_x reduction were initially thought to be soot formation by the natural gas in the absence of the recirculated flue gas and decreased mixing of the natural gas due to elimination of the recirculated flue gas. However, NO_x reduction improved as long-term testing continued; during the last period of long-term testing, NO_x reduction was greater than that achieved with the original reburn system. Operator familiarity with the system and closer control of individual cyclone fuel/air ratios was thought to be the reason for improvement.

- Water injection into the reburn zone was initially thought to improve NO_x reduction during testing with the modified reburn system. A water leak in one of the water-cooled reburn fuel injector guide pipes seemed to correspond directly with increased NO_x reduction. However, controlled water injection tests conducted after completion of the long-term tests provided no improvement in NO_x reduction compared to NO_x reduction achieved during the final series of long-term tests. Controlled water injection did however accomplish the following:

- Lower CO levels; CO emission of 46 ppm and NO_x emissions of 325 ppm (corrected to 3% O_2) were achieved with water injection compared to CO emission of 110 ppm at the same NO_x emission level without water injection.
- The ability to operate the reburn zone at lower stoichiometries (lower NO_x), while maintaining the CO at acceptable levels.

- Reburn systems installed on pressurized furnaces, such as Niles Unit No. 1, can result in a hazardous situation if a casing leak occurs in the vicinity of the reburn zone because of the presence of combustible gases.

  Possible commercial solutions were suggested:

  - Convert pressurized units to balanced draft by adding an induced draft fan and associated equipment.
  - Convert tangent tube pressurized units such as Niles No. 1 to fusion welded walls by adding fusion welds between the tubes.
  - Erect an enclosure around the reburn zone which would operate at a slightly higher positive pressure than the furnace to assure that any leakage would be into the furnace.
  - Erect a "hood-like" structure around the upper part of the furnace so that gas composition could be constantly monitored for possible changes.

  It is unlikely that the first two could be economically justified. However, the third and fourth options would be much less capital-intensive and could be configured to ensure safe reburn system operation.

- Operational constraints place a limitation on the reburn fuel feed rate and corresponding NO_x reduction during reduced load conditions.

  - In order to assure effective tapping of slag from cyclone-fired units, it is necessary to maintain a minimum heat release rate and corresponding coal feed rate to the slag tap region.
  - The minimum heat release in the slag tap region is a function of the furnace size, cyclone design, and coal ash fusibility.
  - Since the fuel fed to the reburn zone does not contribute to heat release in the slag tap zone, reburn fuel must be reduced and finally discontinued as boiler load is reduced.
  - Because the proportion of reburn fuel used at reduced boiler loads is decreased and ultimately turned off below a certain load, overall NO_x reduction is less for reburn systems installed on cyclone-fired furnaces which operate at reduced load for substantial periods. The NO_x concentration in the stack with reduced load however tends to remain nearly constant because the "baseline" NO_x also decreases with reduced load.

- The possibility of tube wastage during operation of the reburn system existed because the reburn process generated a substoichiometric (reducing) gas mixture in the reburn zone. A boiler tube monitoring program was conducted during the reburn system testing to address this possibility. The findings of tube monitoring program were as follows:

- The ultrasonic thickness testing in the waterwall sections was inconclusive since changes in tube thickness were below the sensitivity of the U.T. measurement. However, visual inspection of the waterwalls revealed that the tube surface appeared to be unaffected by reducing atmosphere corrosion.
- Ultrasonic thickness measurements of the superheater and reheater sections, following operation of the original reburn system, showed areas with an approximate 10% wall loss, with wastage in areas of the fifth stage superheater as high as 0.100" over a 20-month timeframe. Indicated tube loss is thought to be from a combination of erosion and corrosion.
- The modified reburn system, without FGR, maintained flue gas mass flows/velocities at basecase levels, thereby minimizing wastage due to erosion. Because tube wastage was not uniform, it is believed that erosion was the larger contributing factor between erosion and corrosion.
- The remaining superheater/reheater tube life analyses performed before and after the reburn project were inconclusive concerning any degradation due to high temperature oxidation. Final inspection values gave higher remaining tube life values than did initially obtained values.

- The cost effectiveness of natural gas reburn retrofit for reducing NO_x emissions from cyclone-fired furnaces depends upon several factors including the following: (1) the baseline NO_x and the expected NO_x removal efficiency of the process over the load range of the boiler, (2) the load profile of the boiler, (3) whether or not it is necessary to terminate reburn operation at some boiler load due to slag tapping requirements and if so at what load this requirement is imposed, and (4) the difference in fuel costs between natural gas and coal. A study of natural gas reburn economics indicated that natural gas reburning is most attractive for newer large units, particularly, base-loaded units.

Parametric testing and long-term testing during the Ohio Edison Reburn Demonstration project provided several recommendations for reducing NO_x and CO emissions by improvements to the reburn system design and operation. These are:

- Improve the control system for feed of coal and air to the cyclones in order to have better and more uniform control of RZS. In this way the reburn system will be better able to operate nearer to the optimum RZS which will provide higher NO_x reduction without aggravating CO levels.

- CO levels turned out to be a limiting factor for NO_x reduction. Decreases in RZS could clearly produce lower NO_x, but at the expense of unacceptably high CO. Better mixing of air in the burnout zone and biasing residence times toward the burnout zone, rather than the reburn zone, may result in lower NO_x because of the ability to achieve acceptable CO levels.

- Introduce a small, controlled amount of H_2O with the natural gas in the reburn zone to reduce CO formation; this would allow lower RZS, higher NO_x reduction and acceptably low CO.

- Use stainless steel for water-cooled guide tubes and other components which are subjected to high temperatures in order to reduce the possibility of failure of reburn zone components.

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APPENDIX A

ULTRASONIC THICKNESS (UT) MEASUREMENTS AT OHIO EDISON COMPANY'S NILES PLANT UNIT NO. 1

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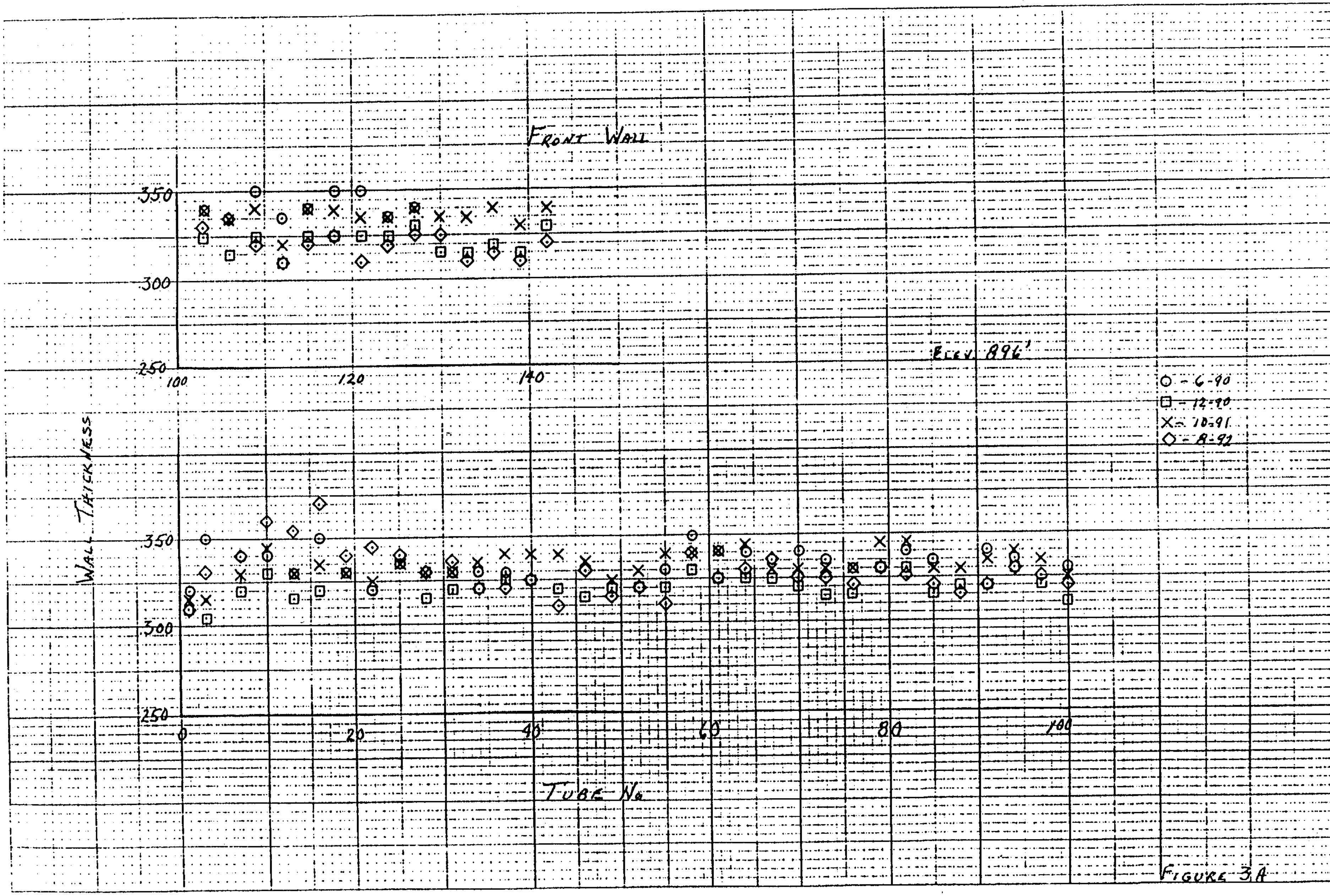
August 1992

Synopsis of Appendix A

This appendix is twenty (20) plots of waterwall, secondary superheater, and reheater tube wall thickness measured during June 1990, December 1990, October 1991, and August 1992. The plots are labeled Figure 3A through Figure 12B. A discussion of the plots is given in Section 14.



FRONT WALL
ELEV 896'
○ - 6-90
□ - 12-90
X - 10-91
◇ - 8-92
WALL THICKNESS
TUBE No
350
300
250
100
120
140
0
20
40
60
80
100

FIGURE 3A

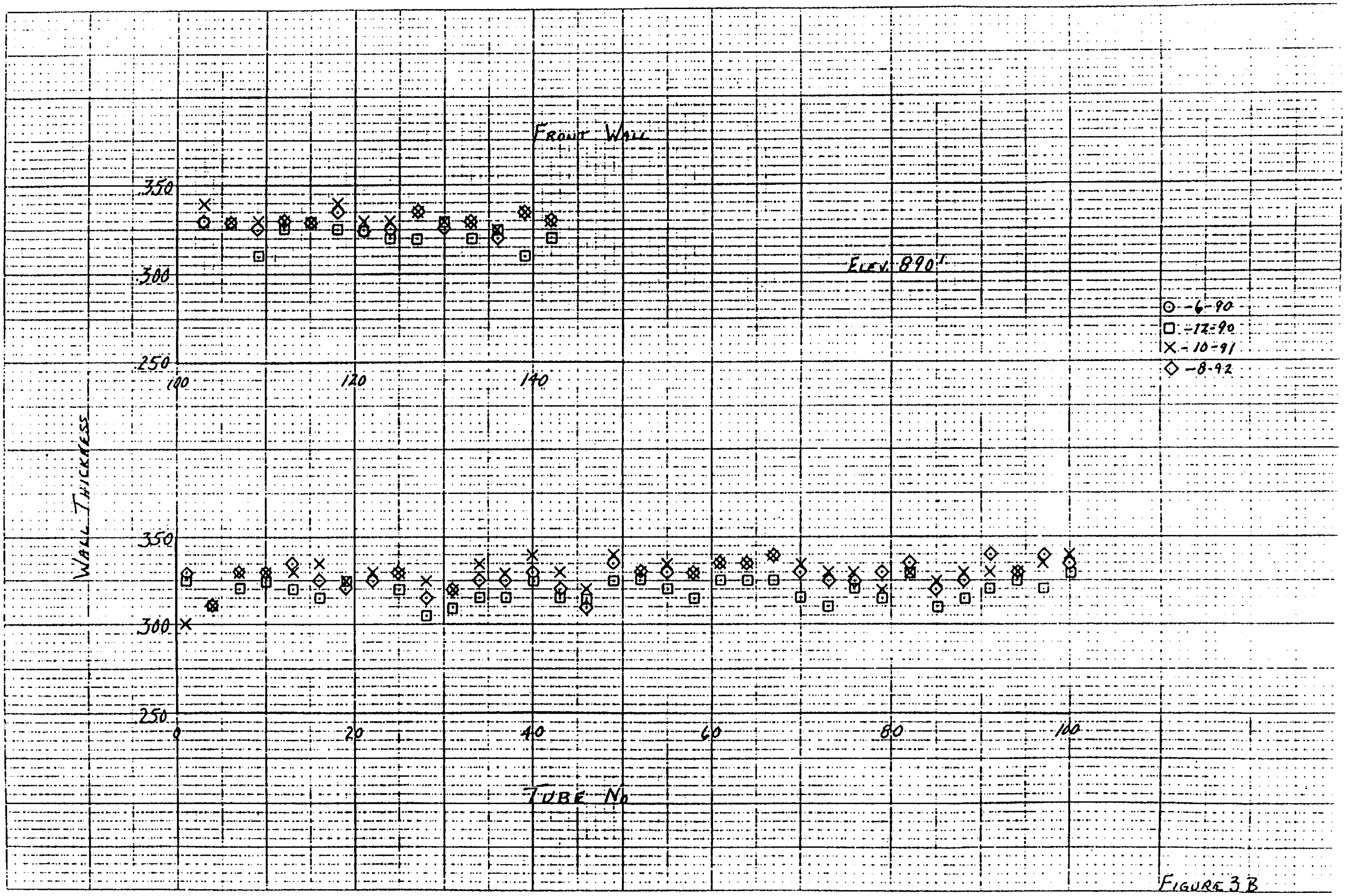
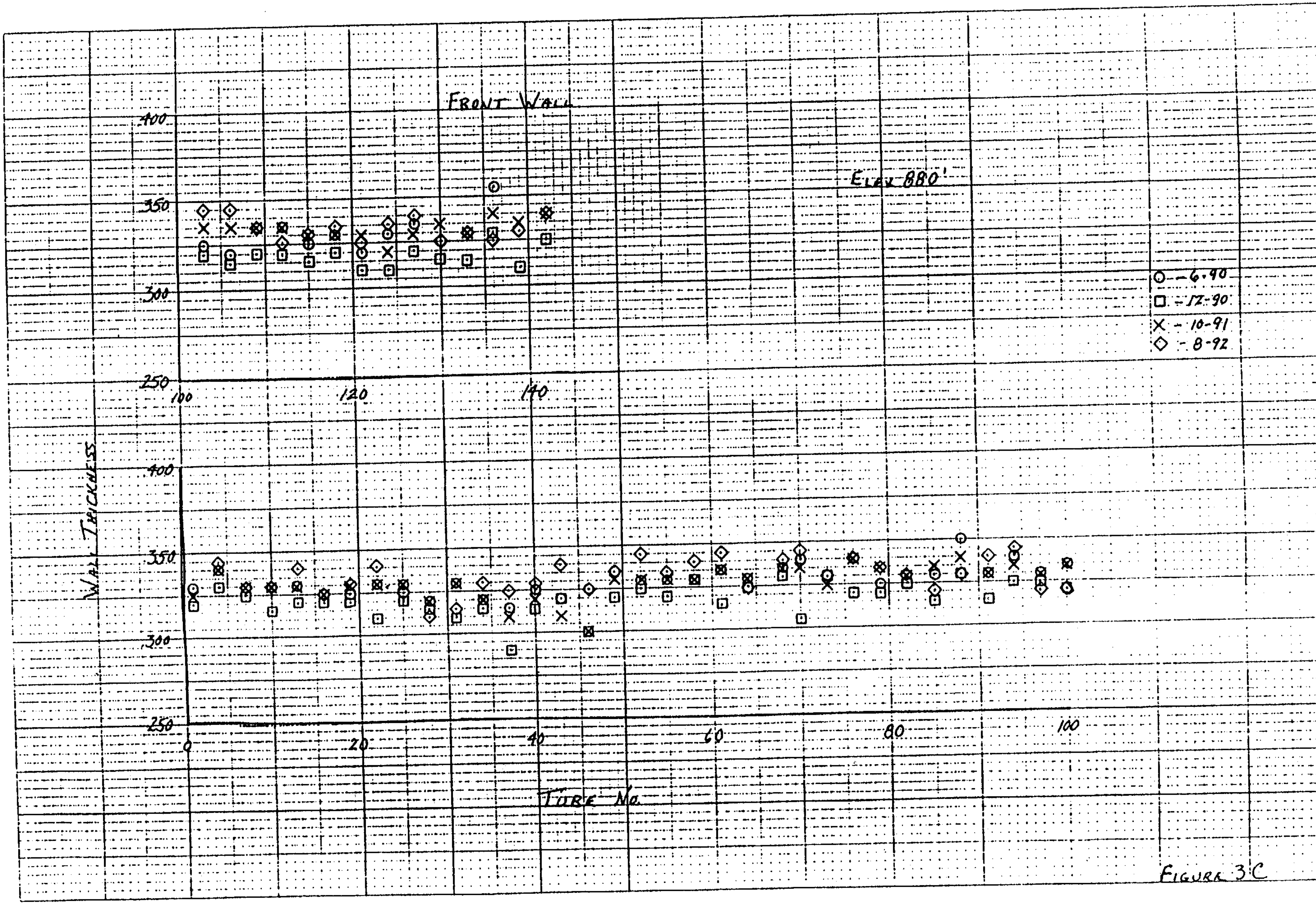

Front Wall
Elev. 890'
⊙ - 6-90
□ - 12-90
X - 10-91
◇ - 8-92
350
300
250
100
120
140
Wall Thickness
350
300
250
0
20
40
60
80
100
Tube No

Figure 3B



FRONT WALL
ELEV 880'
○ - 6-90
□ - 12-90
X - 10-91
◇ - 8-92
WALL THICKNESS
400
350
300
250
100
120
140
0
20
40
60
80
100
TUBE NO.

FIGURE 3C

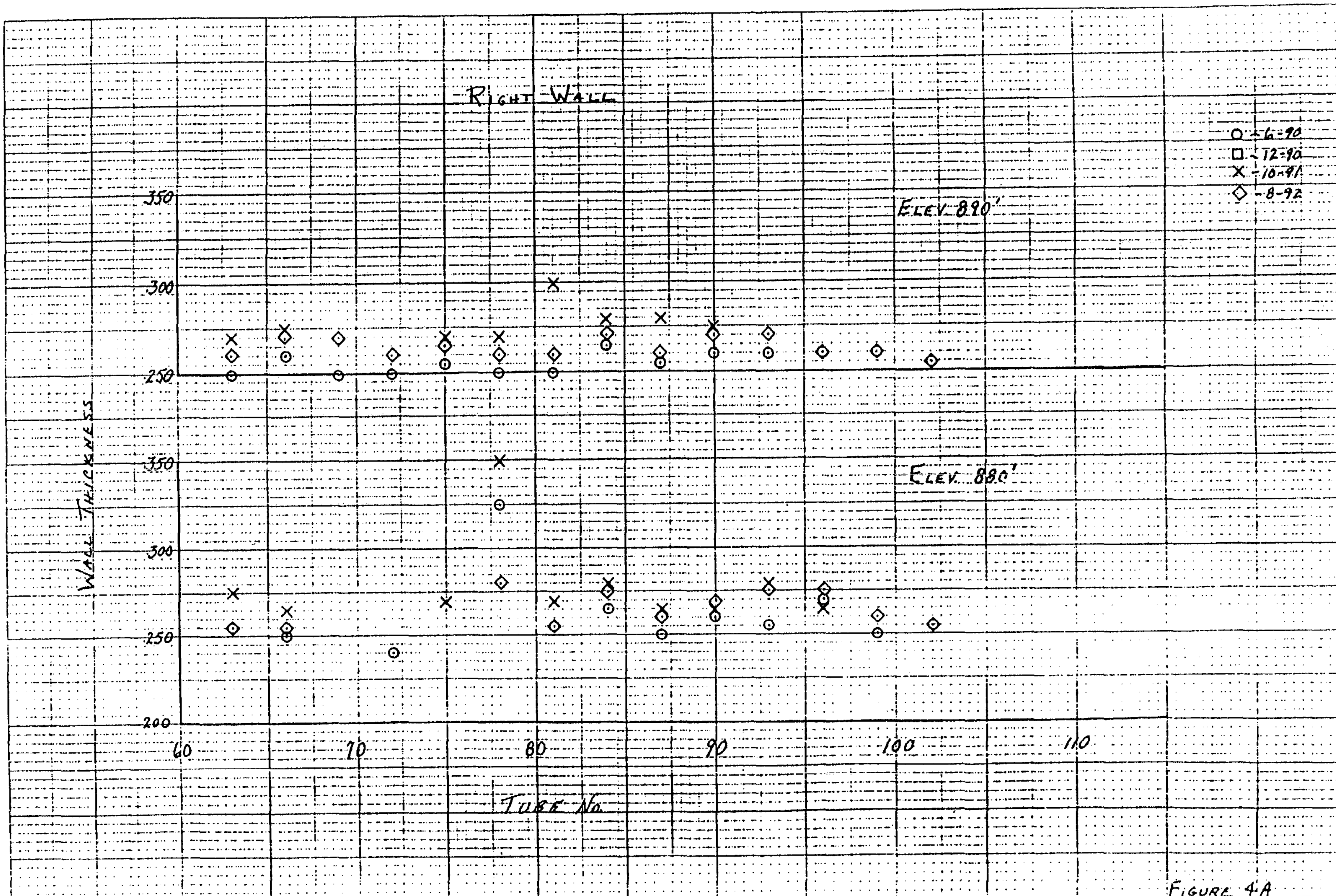
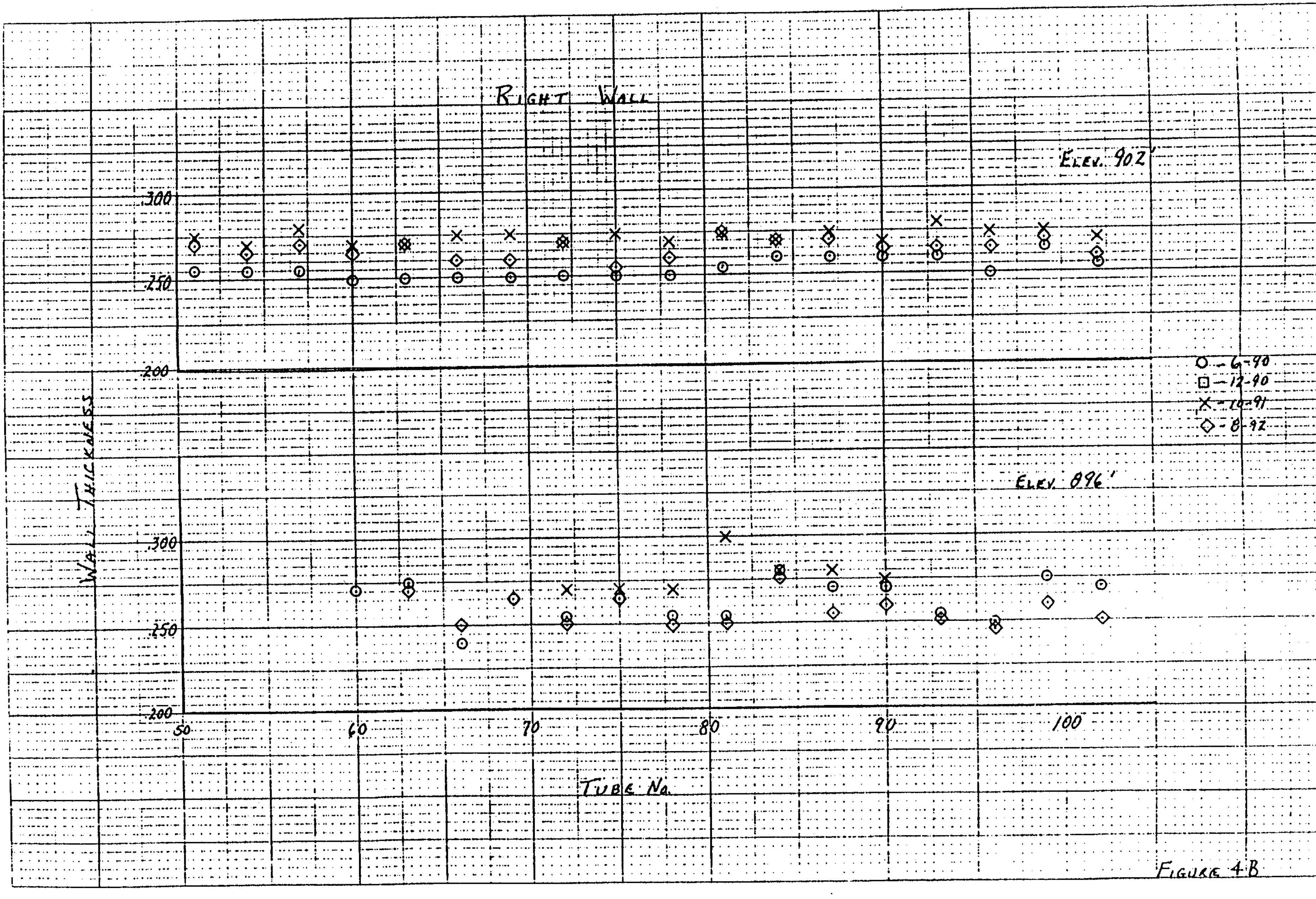
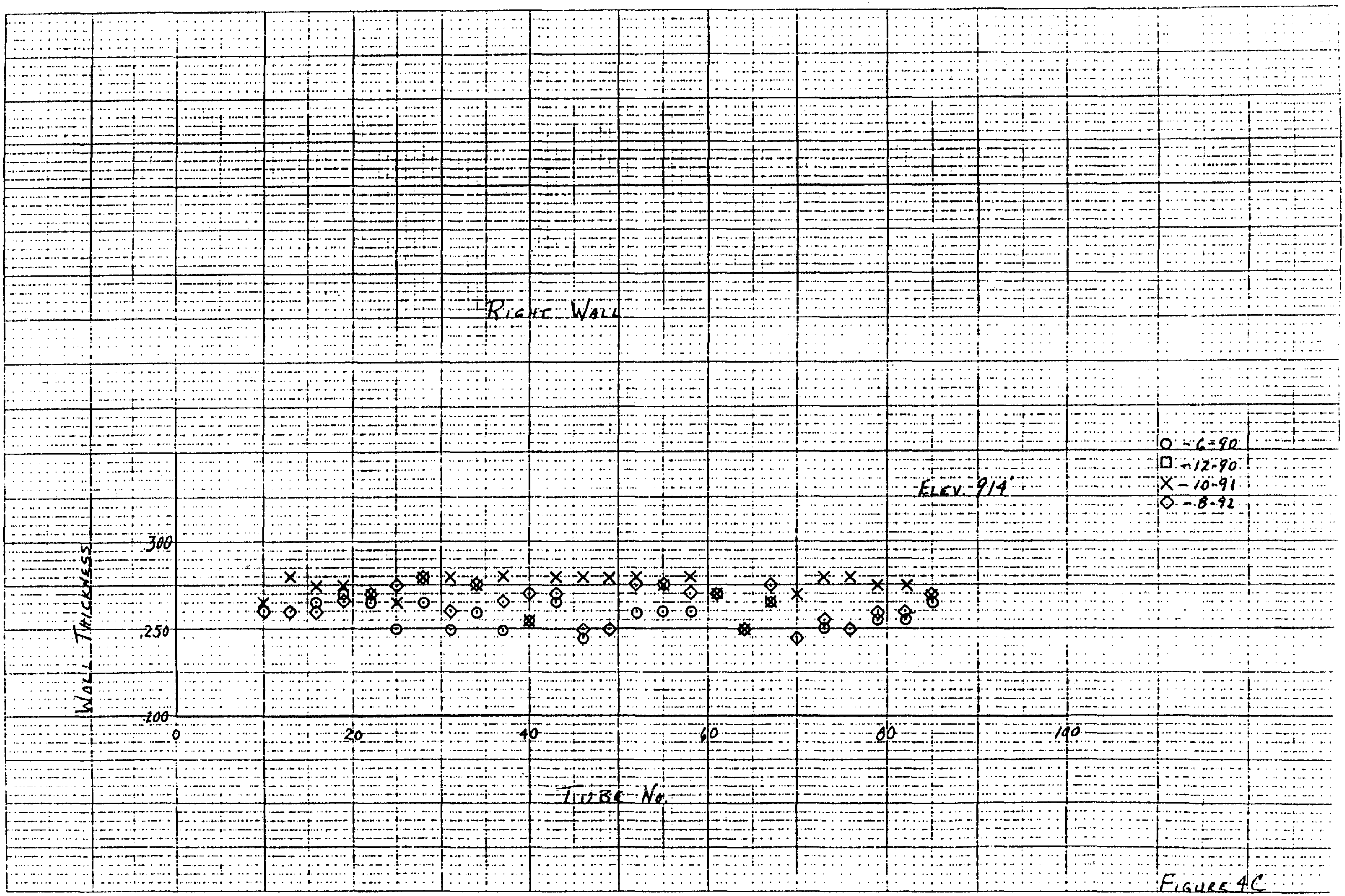


FIGURE 4A

DIETZGEN CORPORATION


RIGHT WALL
ELEV. 902'
ELEV. 896'
○ - 6-90
□ - 12-90
X - 10-91
◇ - 8-92
WALL THICKNESS
.300
.250
.200
50
60
70
80
90
100
TUBE No.
FIGURE 4-B


Right Wall
○ - 6-90
□ - 12-90
× - 10-91
◇ - 8-92
Elev. 914'
Wall Thickness
.300
.250
.100
0
20
40
60
80
100
Tube No.
Figure 4C

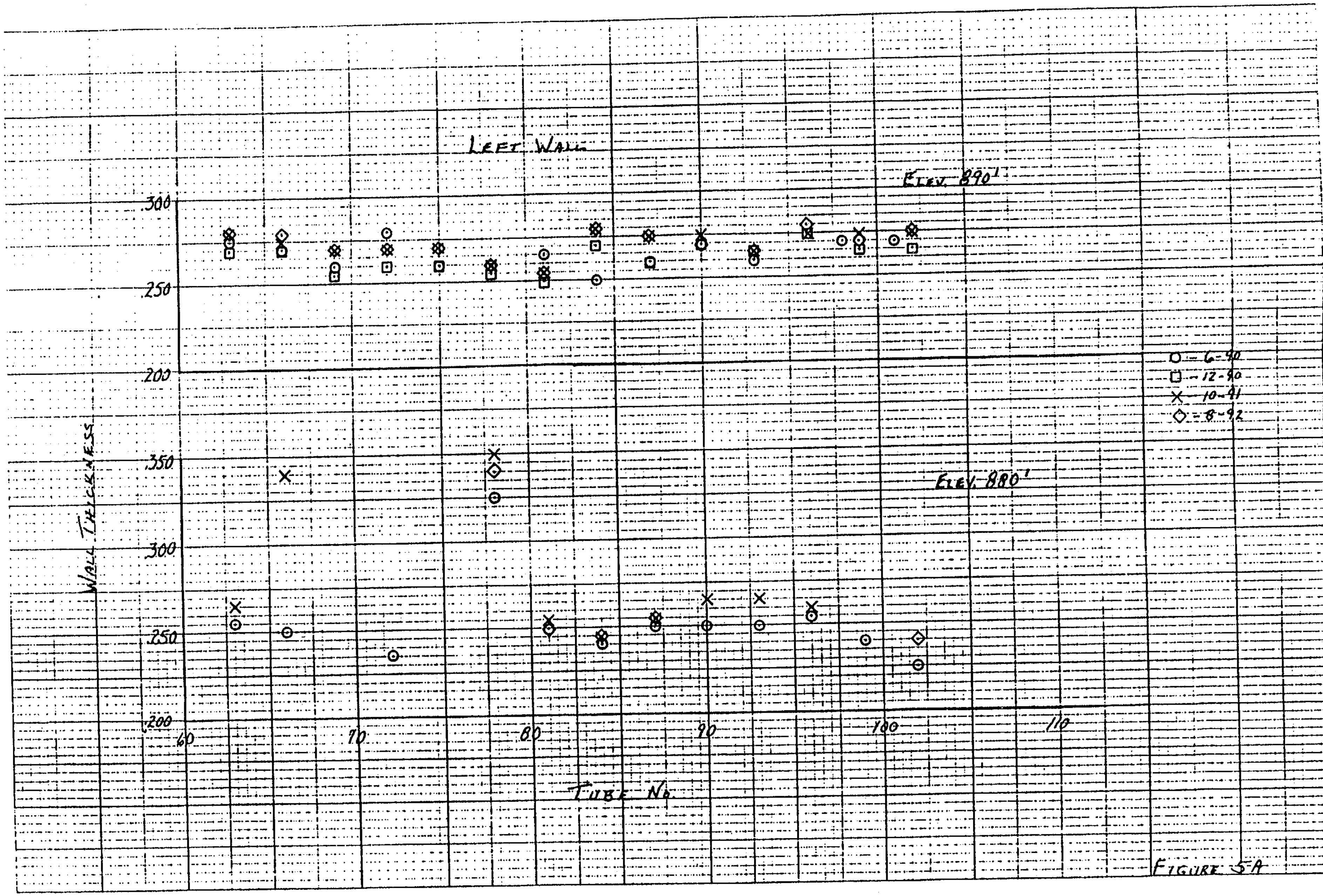
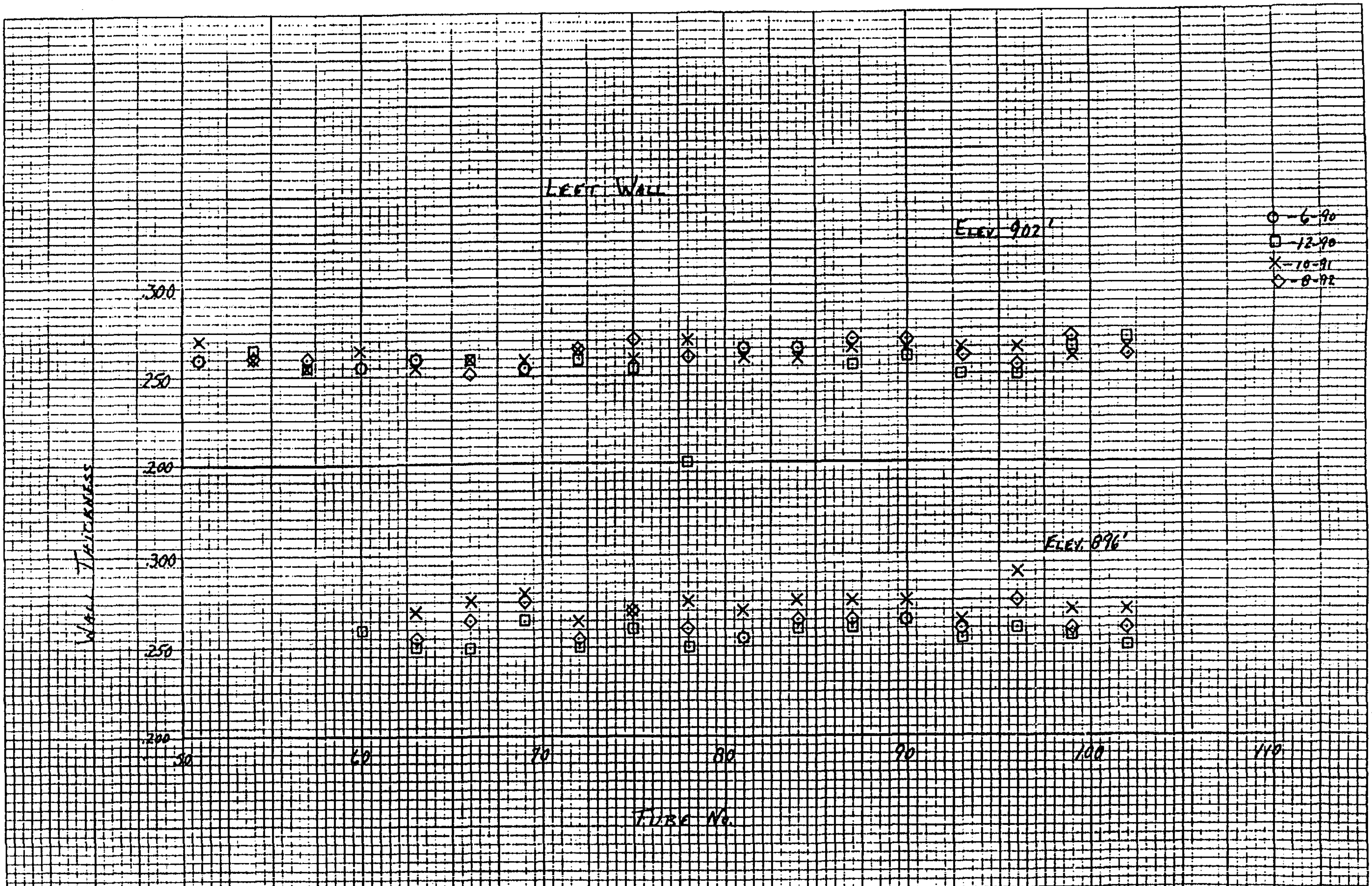
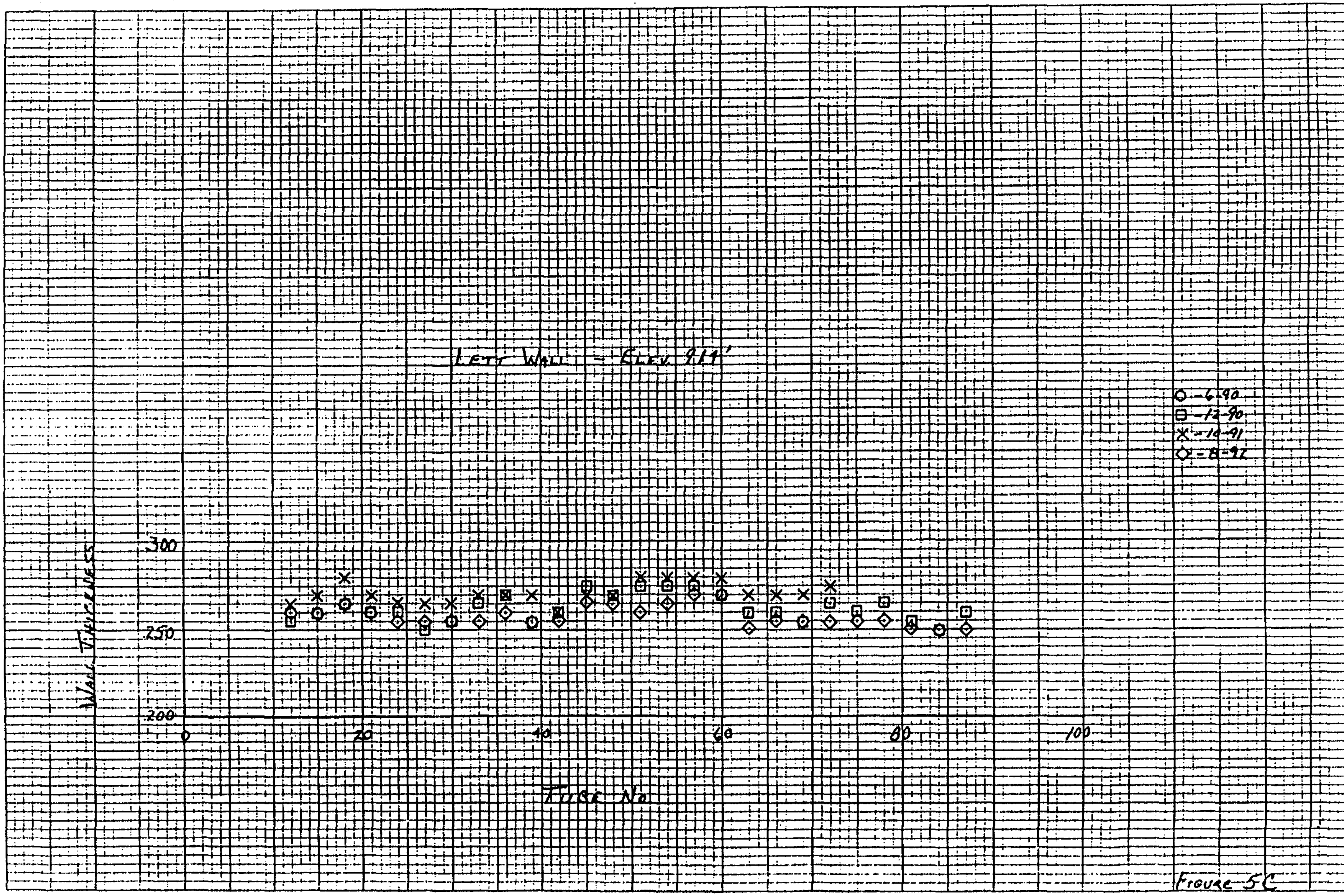

LEFT WALL
ELEV. 890'
ELEV. 880'
○ - 6-90
□ - 12-90
× - 10-91
◇ - 8-92
WALL THICKNESS
.300
.250
.200
.350
.300
.250
.200
60
70
80
90
100
110
TUBE No.

FIGURE 5A



LEFT WALL
ELEV. 902'
ELEV. 896'
-6-90
-12-90
-10-91
-8-92
.300
250
.200
.300
.250
.200
50
60
70
80
90
100
110
WALL THICKNESS
TUBE No.

FIGURE 5B



Left Wall - Elev 911'
O - 6-90
□ - 12-90
X - 10-91
◇ - 8-92
Wall Thickness
300
250
200
0
20
40
60
80
100
Tube No

Figure 5C

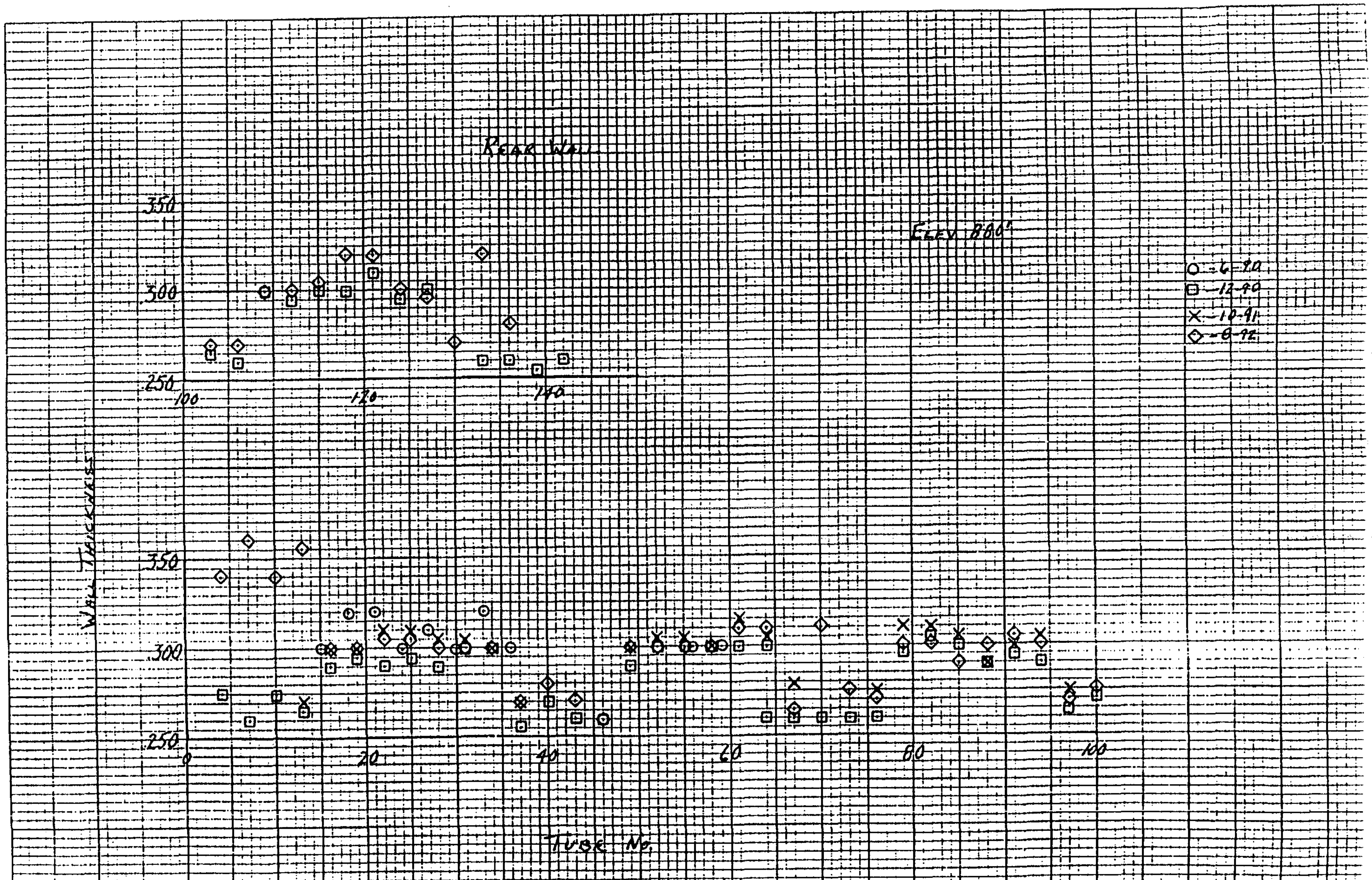

REAR WALL
ELEV 800'
○ - 6-90
□ - 12-90
× - 10-91
◇ - 8-92
350
300
250
100
120
140
WALL THICKNESS
350
300
250
0
20
40
60
80
100
TUBE NO.

FIGURE 6A

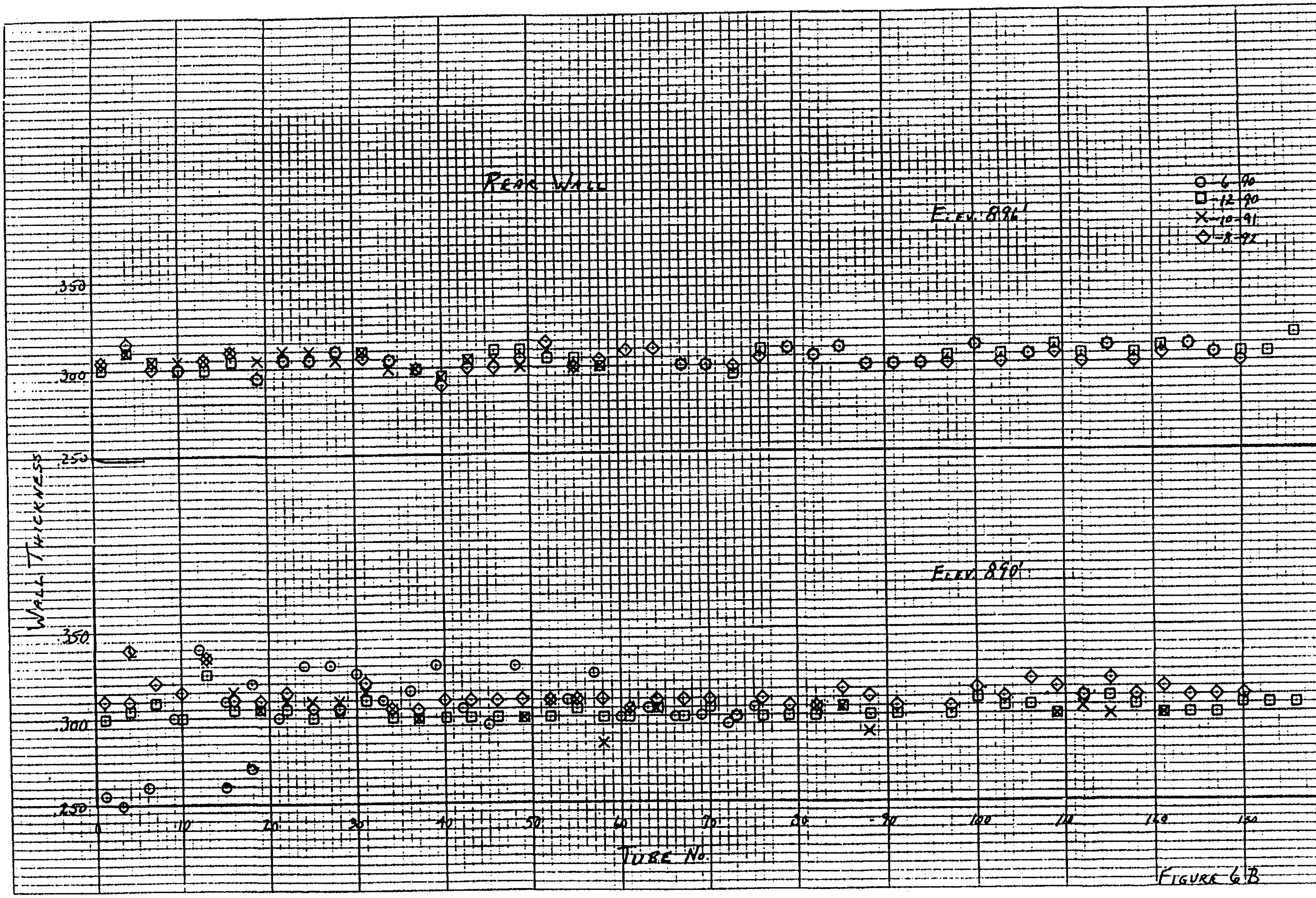

REAR WALL
ELEV. 896'
ELEV. 890'
O - 6-90
□ - 12-90
X - 10-91
◇ - 8-92
WALL THICKNESS
.350
.300
.250
TUBE No.
0
10
20
30
40
50
60
70
80
90
100
110
120
130

FIGURE 6B

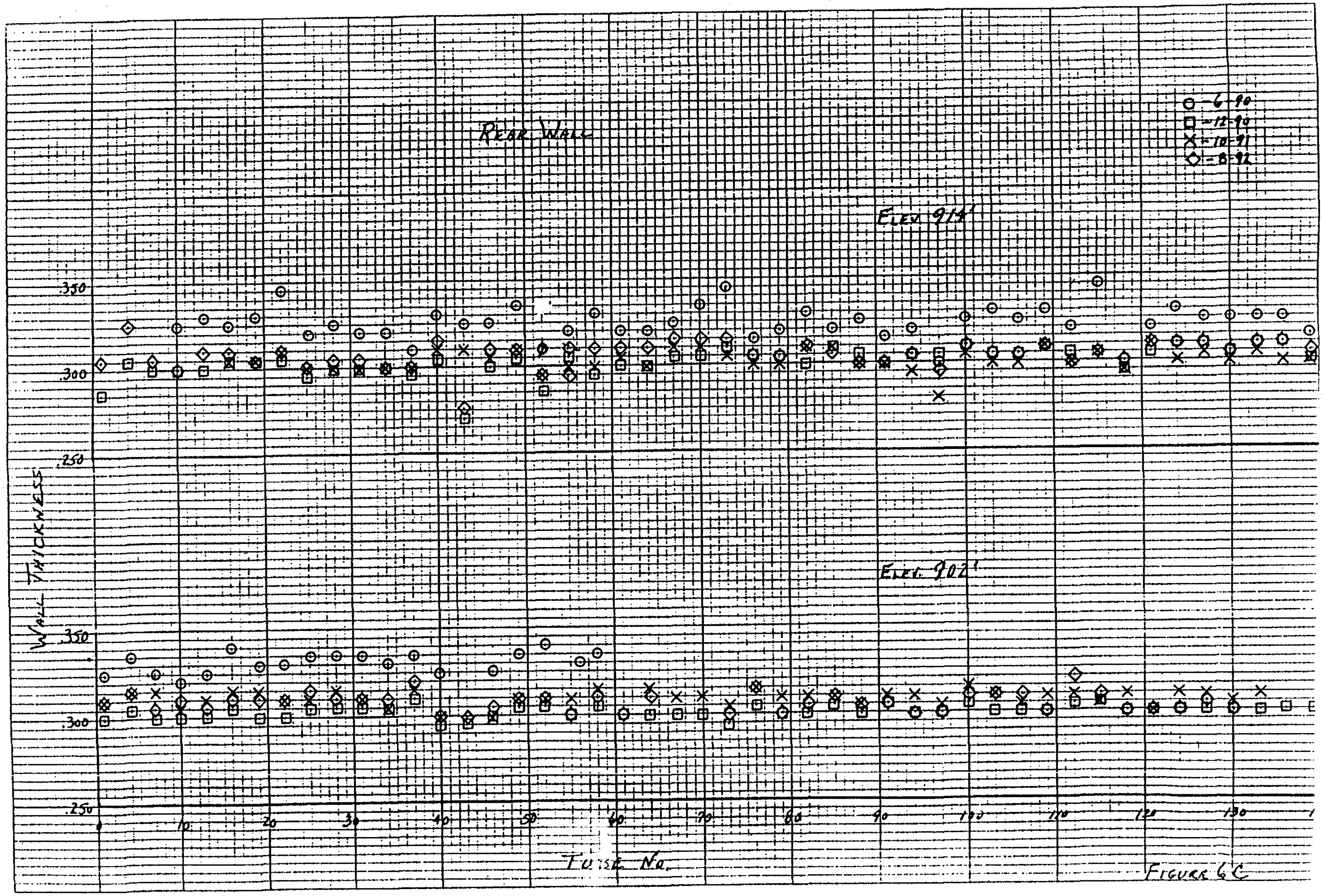
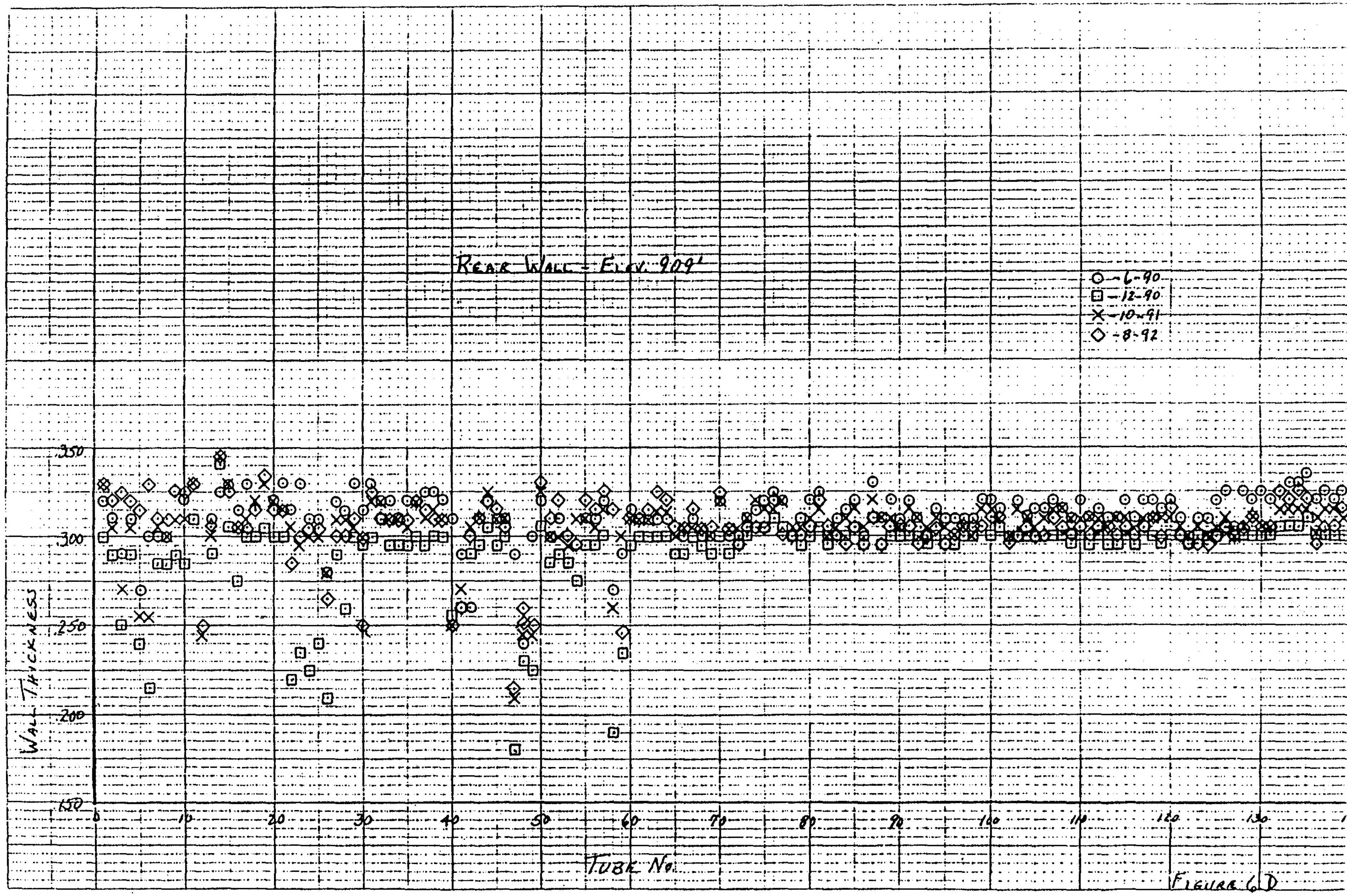
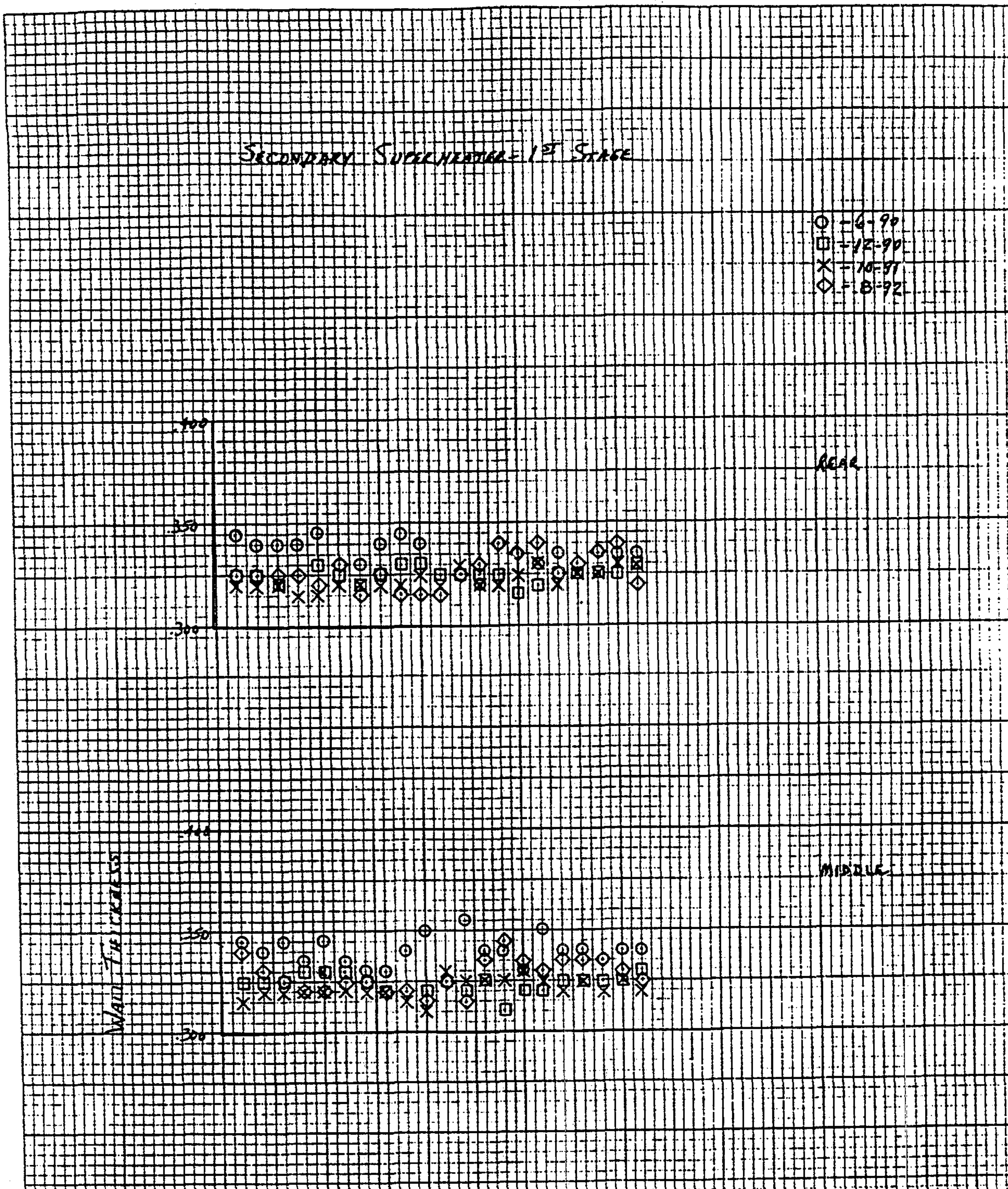

REAR WALL
○ - 6-90
□ - 12-90
X - 10-91
◇ - 8-92
ELEV. 914'
ELEV. 902'
WALL THICKNESS
.350
.300
.250
.350
.300
.250
0
10
20
30
40
50
60
70
80
90
100
110
120
130
TUBE NO.

FIGURE 6C



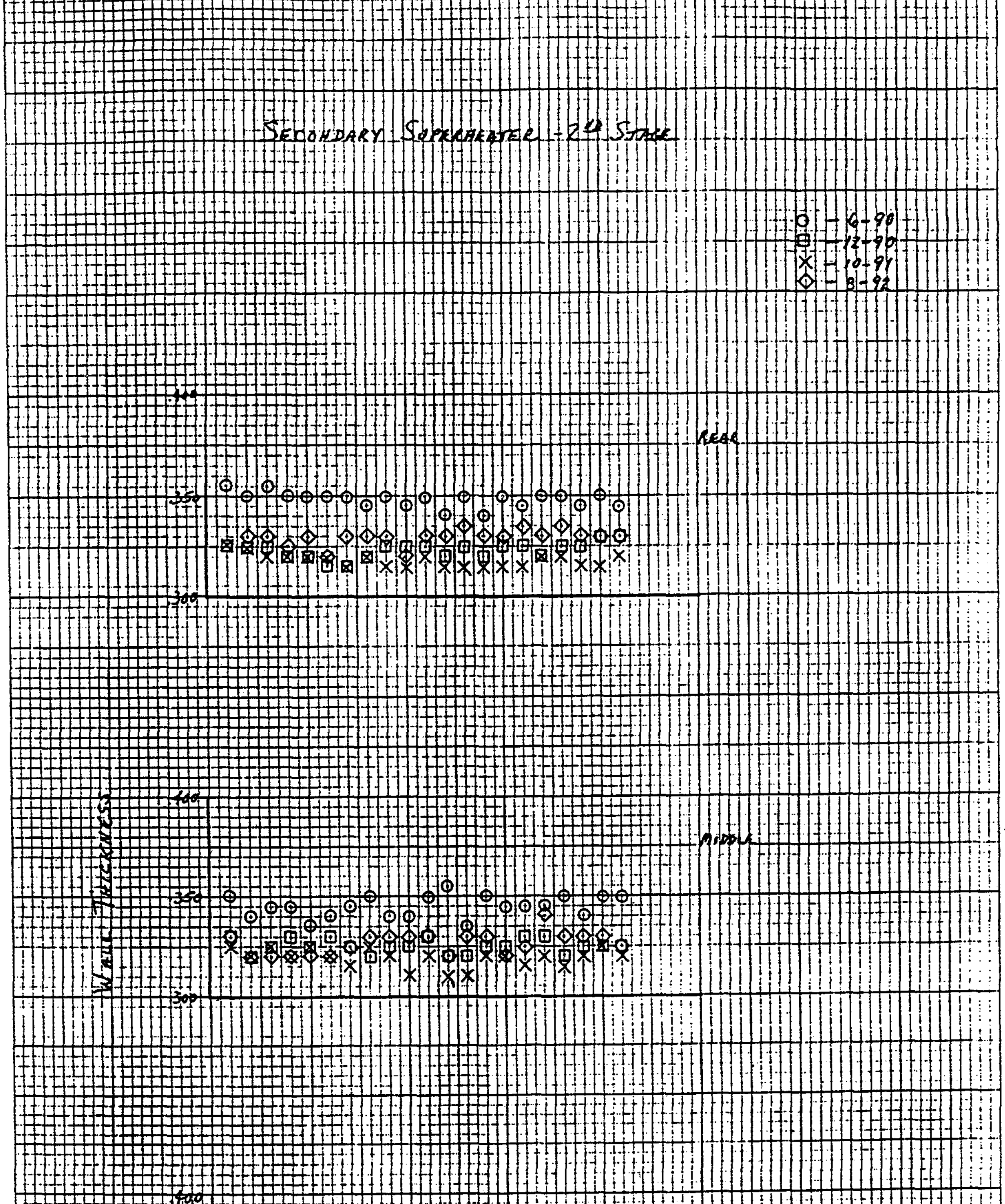
REAR WALL - ELEV. 909'
○ - 6-90
⊡ - 12-90
X - 10-91
◇ - 8-92
350
300
250
200
150
0
10
20
30
40
50
60
70
80
90
100
110
120
130
WALL THICKNESS
TUBE No.

FIGURE 6D



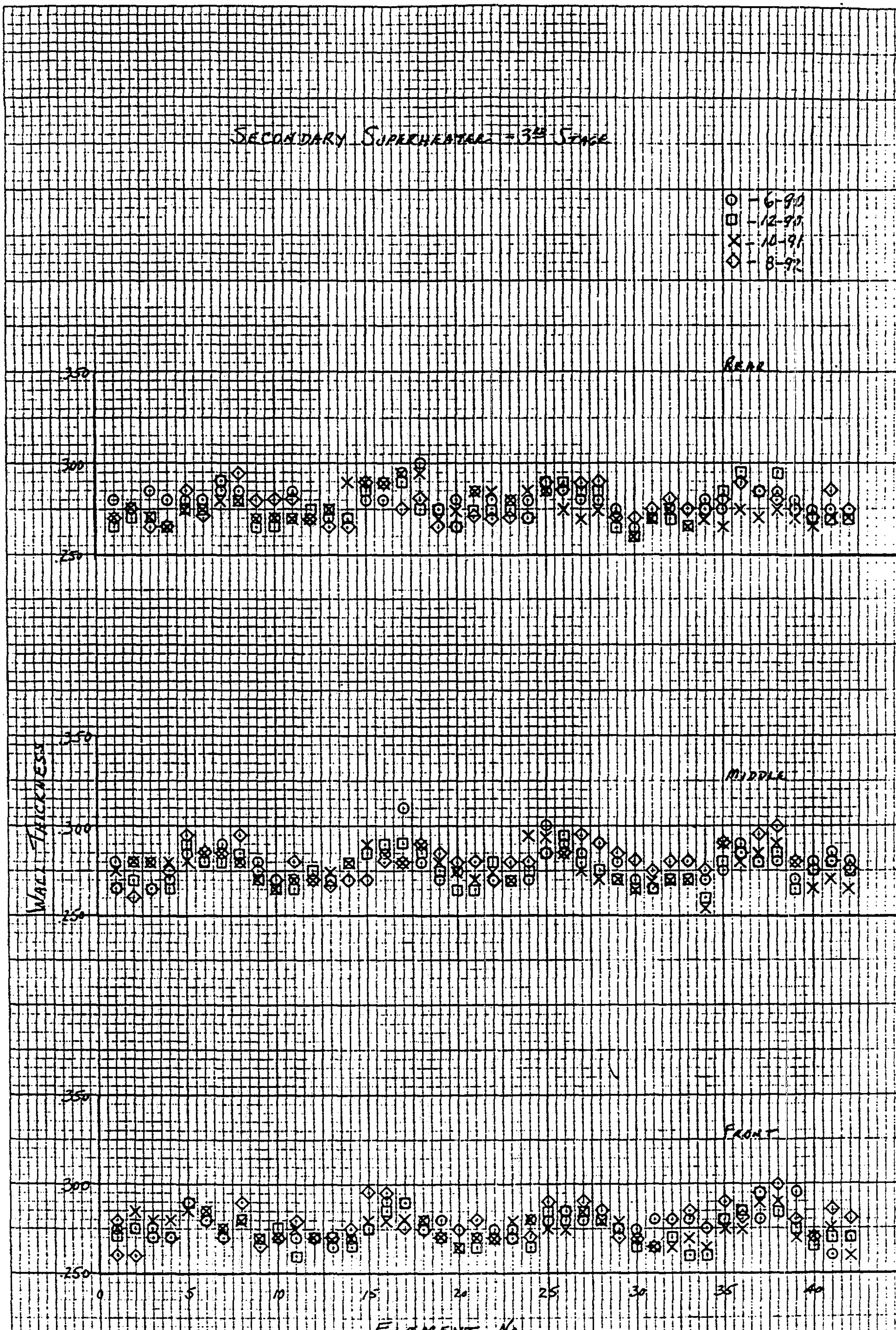
SECONDARY SUPERHEATER - 1ST STAGE
⊙ - 6-90
□ - 12-90
X - 10-91
◇ - 8-92
.400
.350
.300
REAR
MIDDLE
FRONT
WALL THICKNESS
0
5
10
15
20
25
ELEMENT NO.

FIGURE 7



SECONDARY SUPERHEATER - 2nd STAGE
○ - 6-90
□ - 12-90
X - 10-91
◇ - 8-92
REAR
MIDDLE
FRONT
WALL THICKNESS
400
350
300
0
5
10
15
20
25
ELEMENT No.

FIGURE 8



SECONDARY SUPERHEATER - 3rd STAGE
⊙ - 6-90
□ - 12-90
X - 10-91
◇ - 8-92
REAR
MIDDLE
FRONT
WALL THICKNESS
.350
.300
.250
0
5
10
15
20
25
30
35
40
ELEMENT No.

FIGURE 9

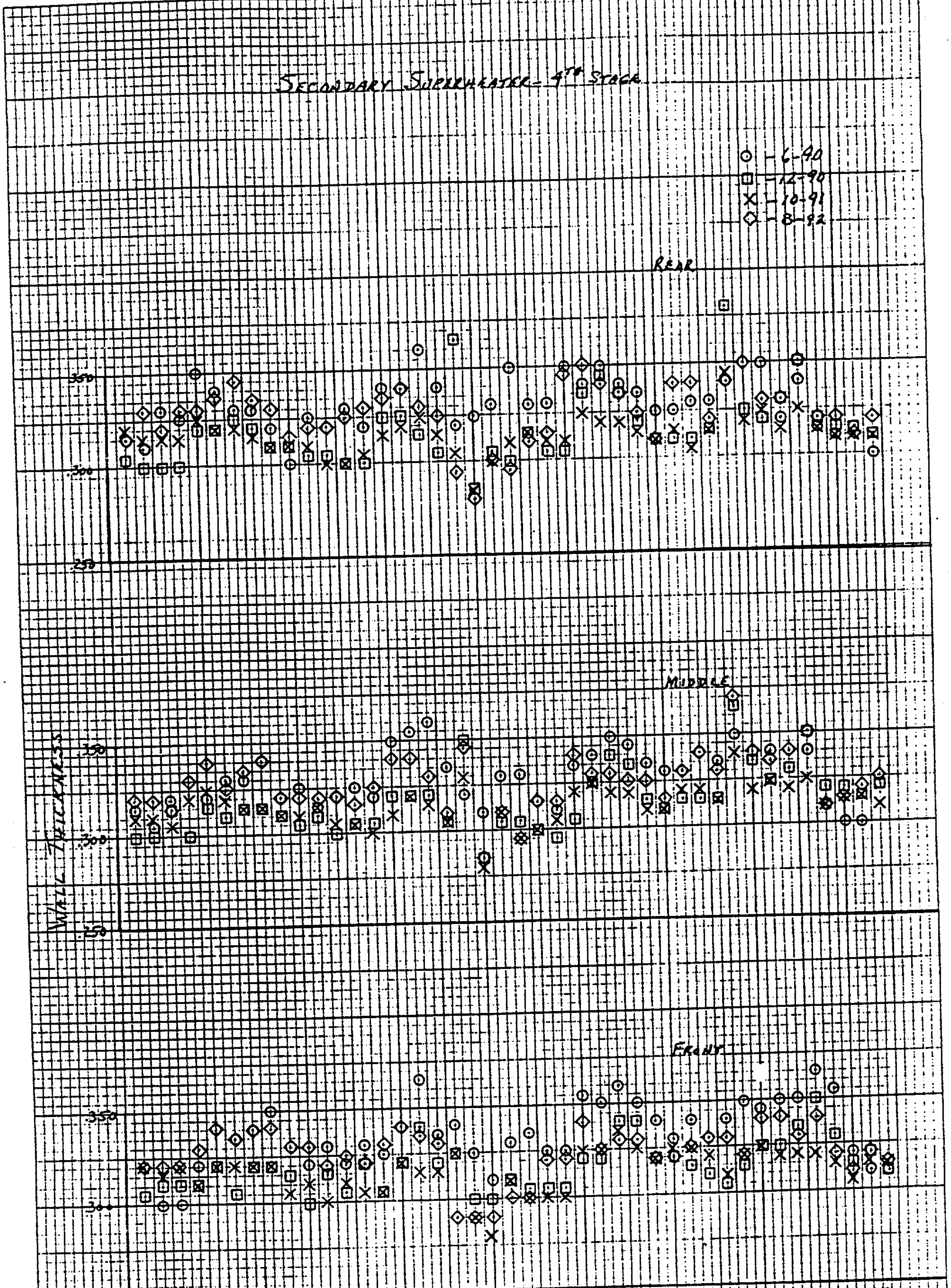
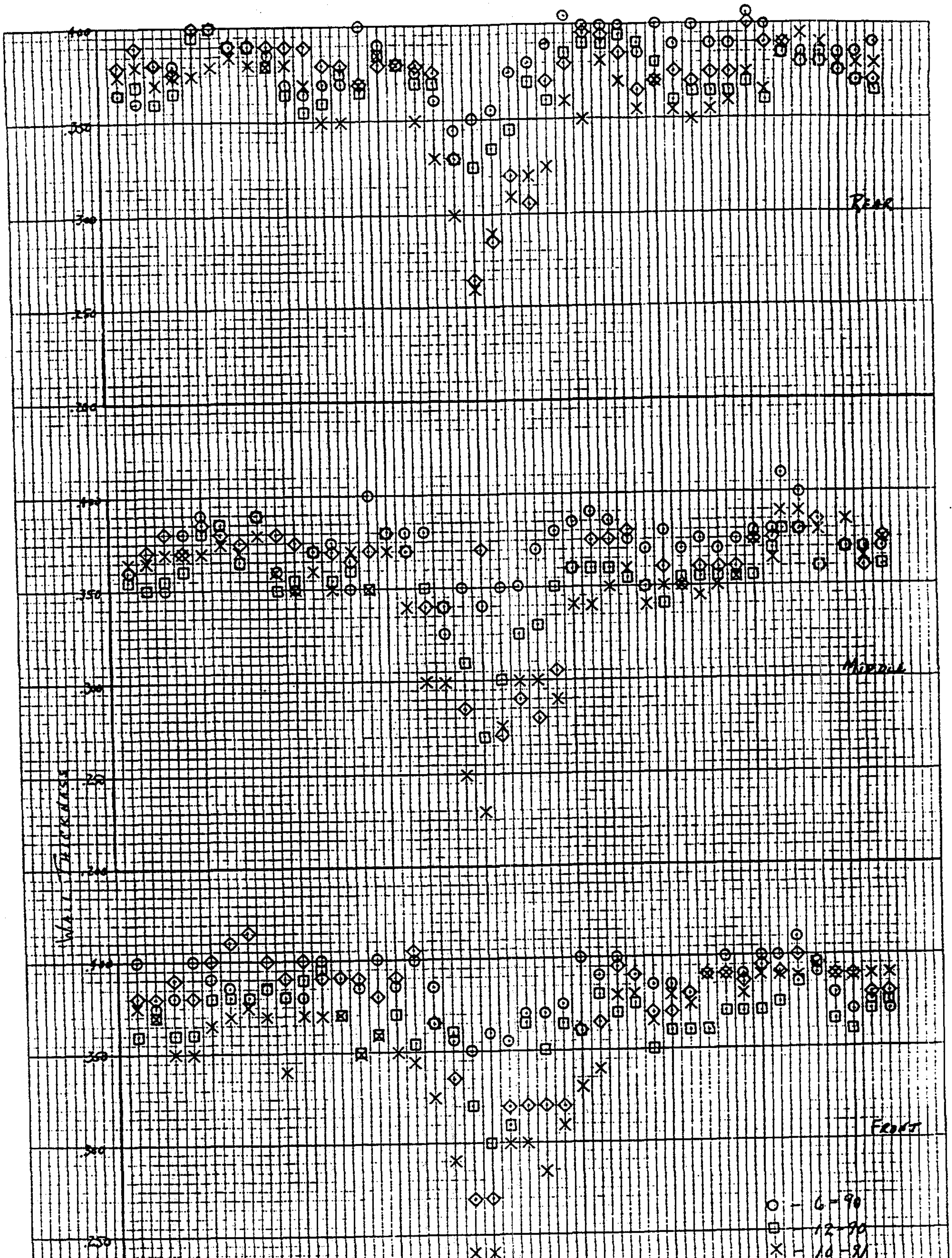
SECONDARY SUPERHEATER - 4TH STAGE
⊙ - 6-90
⊡ - 12-90
X - 10-91
◇ - 8-92
REAR
MIDDLE
FRONT
WALL THICKNESS
.350
.300
.250
0
5
10
15
20
25
30
35
40
ELEMENT No

FIGURE 10



SECONDARY SUPERHEATER 5TH STAGE FIGURE 11

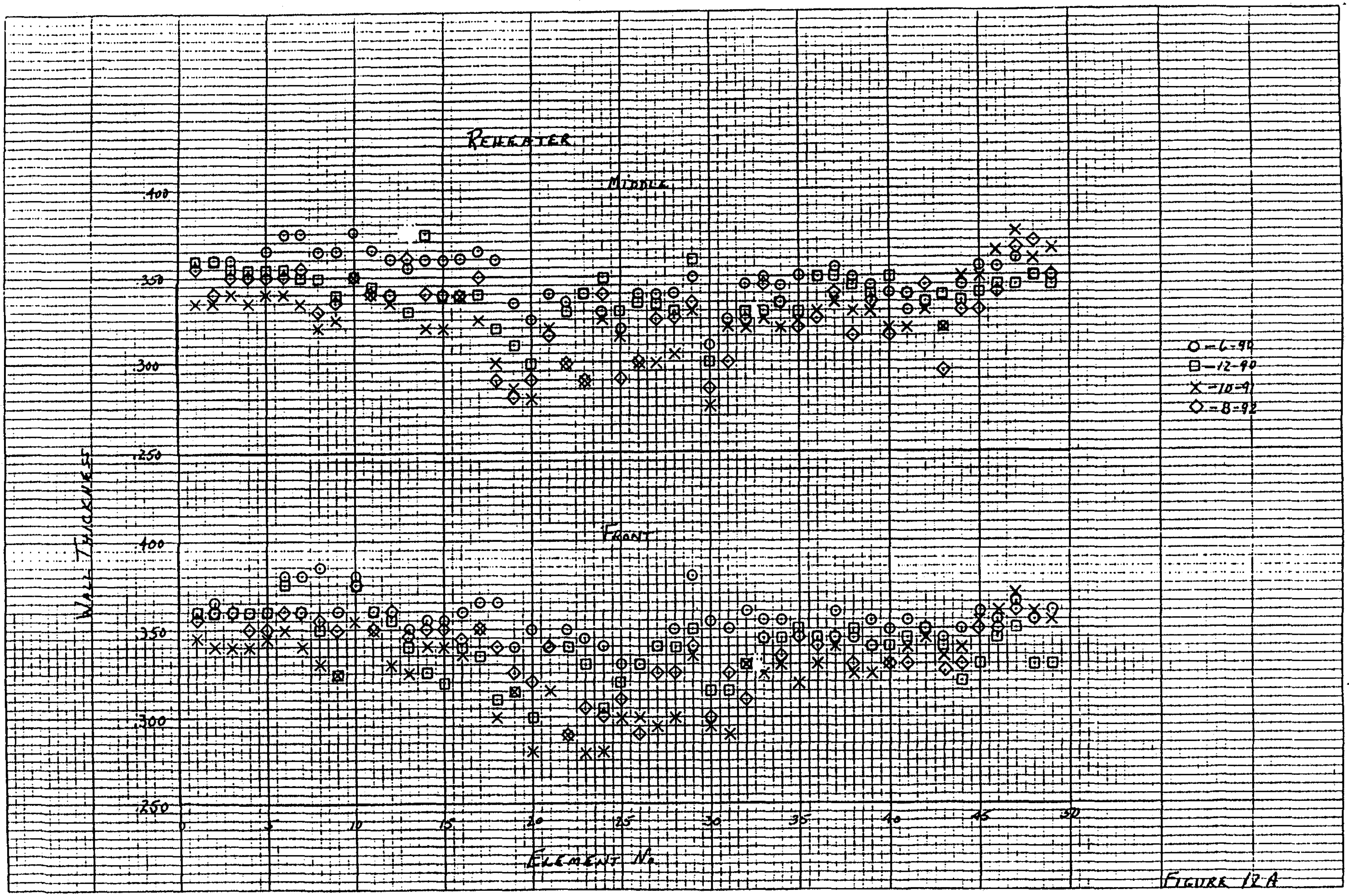
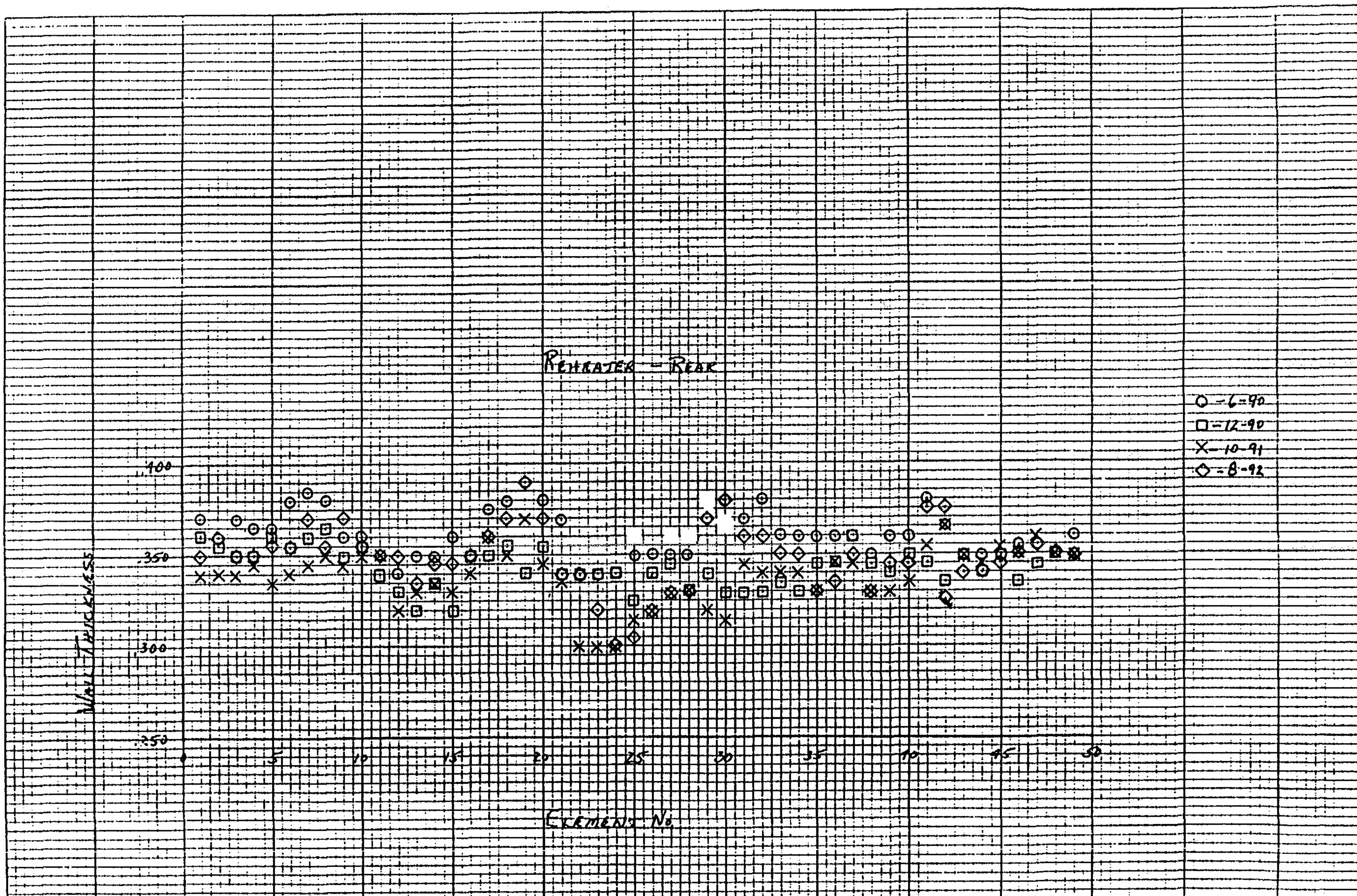

REHEATER
MIDDLE
FRONT
WALL THICKNESS
ELEMENT No.
.400
.350
.300
.250
0
5
10
15
20
25
30
35
40
45
50
○ – 6-90
□ – 12-90
× – 10-91
◇ – 8-92

FIGURE 12-A


REHEATER - REAR
○ - 6-90
□ - 12-90
X - 10-91
◇ - 8-92
.400
.350
.300
.250
5
10
15
20
25
30
35
40
45
50
WALL THICKNESS
ELEMENT NO.
FIGURE 12 B

APPENDIX B

Memorandum, A. L. Waddingham to Sher Durrani,
"Niles No. 1 Boiler Waterwall Survey"

Ohio Edison
Chemical and Material Applications Center
1501 Commerce Drive
Stow, Ohio 44224

January 9, 1991

Synopsis of Appendix B

This appendix is a memorandum by A. L. Waddingham of Ohio Edison Co. describing the condition of the boiler tubes at Niles No. 1 during an inspection of December 30, 1990. The appendix also includes twelve (12) photographs taken during the inspection.

FILE N5

C~~AR~~ - FYI
~~LAG~~
F

OHIO EDISON
The Energy Makers

MEMORANDUM

TO: SMDurrani
14th Floor

January 9, 1991

FROM: ALWaddingham
Central Chemical Lab

SUBJECT: Niles No. 1 Boiler Waterwall Survey

On December 30, 1990, I monitored the subject inspection which was performed by Combustion Engineering's ultrasonic testing company. All readings were obtained by using a Krautkramer Branson USK7 Flaw detector with a contoured, dual-element 5 MHz probe. Calibration was performed on a machined tube and was checked after each set of readings. The surface of the tubes was cleaned by sand blasting to white metal; the couplant was a cellulose-gel type.

The following is a list of test strips that were sand-blasted:

Elevation	
914'	All four walls
909'	Rearwall only
902'	All four walls
896'	" " "
890'	" " "
880'	" " "

It should be noted that all areas were tested except the front wall strips (target wall) at elevations 914' and 902', due to inaccessibility, and every 3rd tube was tested at each elevation except for elevation 909' in which they did every tube. Furthermore, readings were obtained on the left, center and right of each tube unless access was not available or studding obstructed the transducer.

Although a copy of the data was not obtained, I did take several photographs of the "surface" conditions (see attachments). Based on the visual examination, I feel that very little external "reducing" corrosion has occurred. Some low values were recorded at elevation 909'. The low numbers were not due to external corrosion, but due to internal gouging at the bond.

If you have any questions, or require additional information, please advise.

Al Waddingham
A. L. Waddingham

PITCH DATE

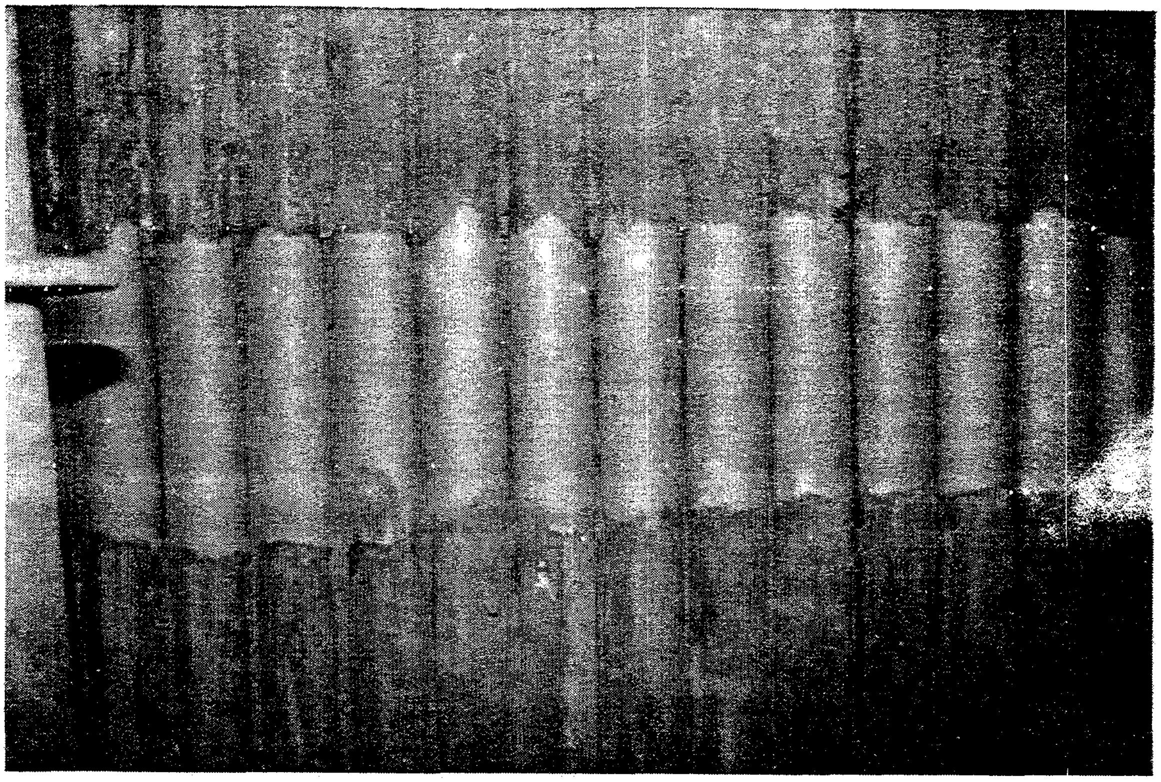
ALW/lrp

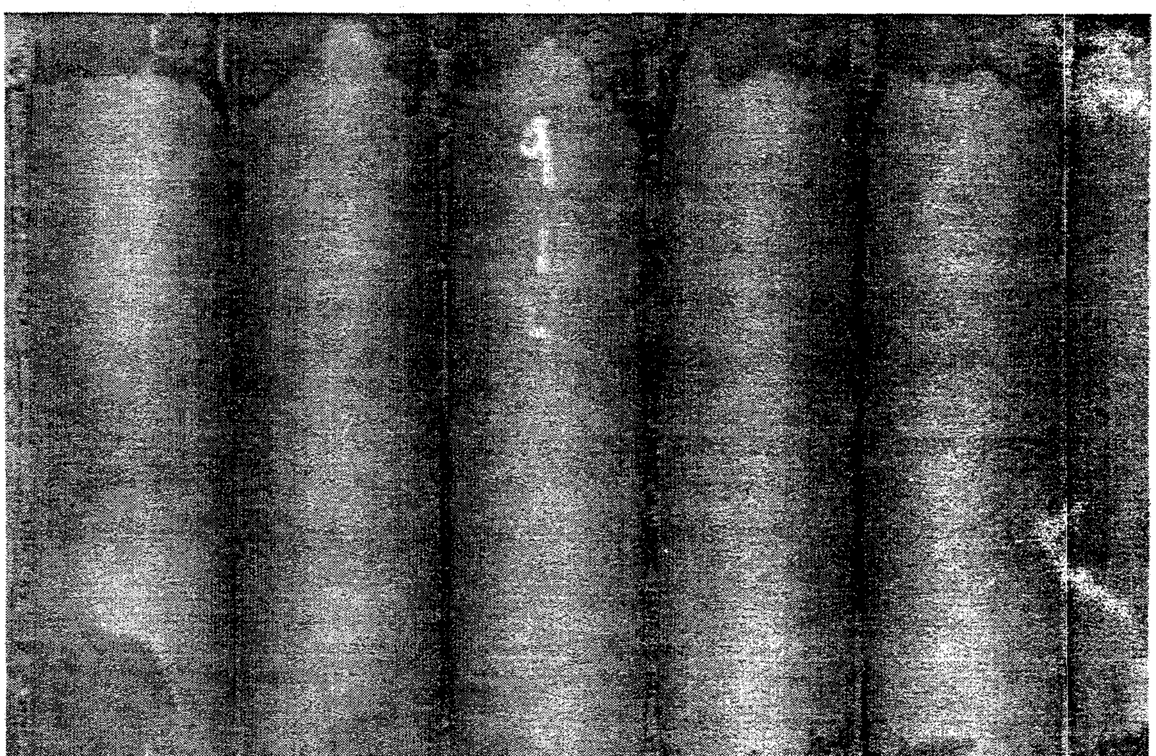
cc: HCCouch
JMMurray
DLTackett
KHWorkman

X

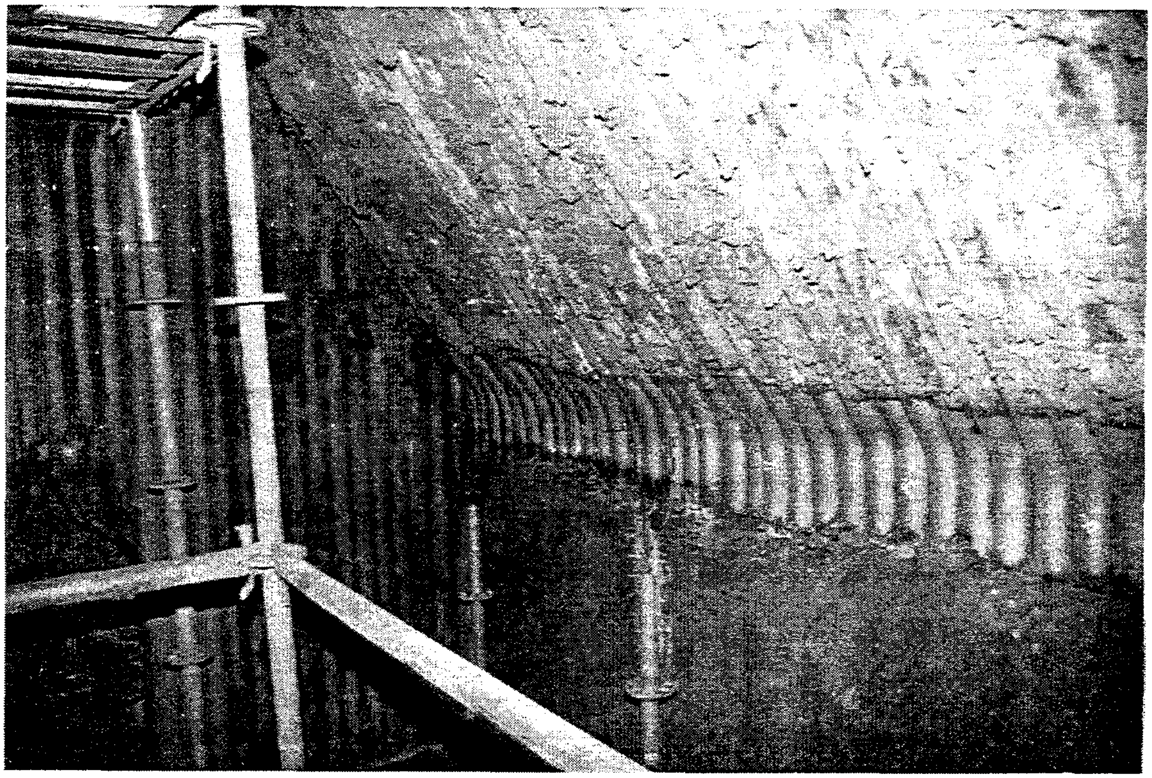
RECEIVED
JAN 14 1991
GEN. PLT.
CONST. & PROJECTS

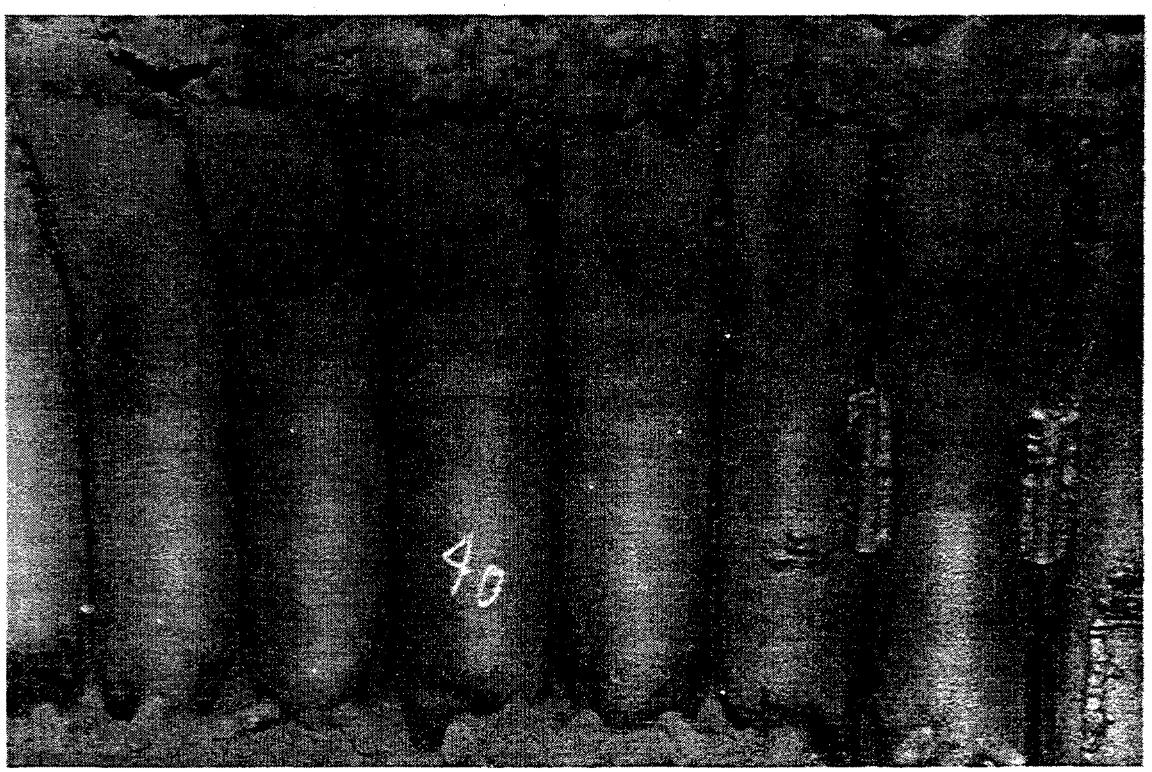
ELEVATION 914′



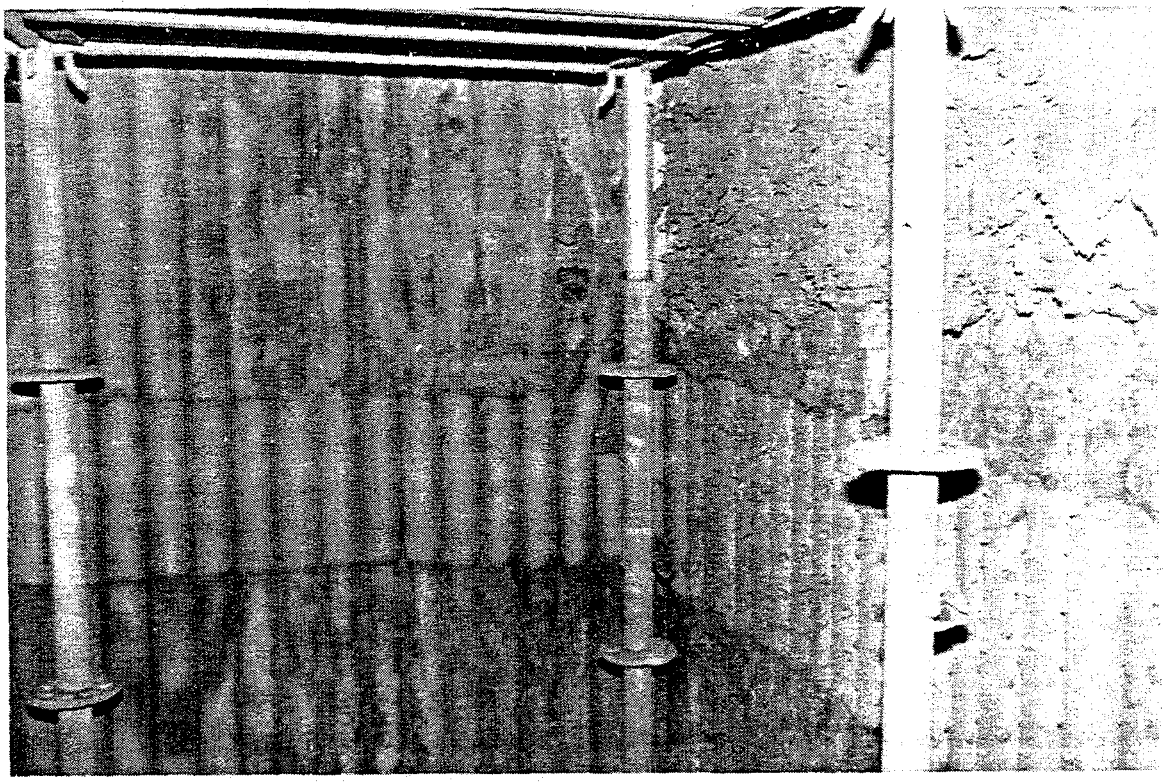


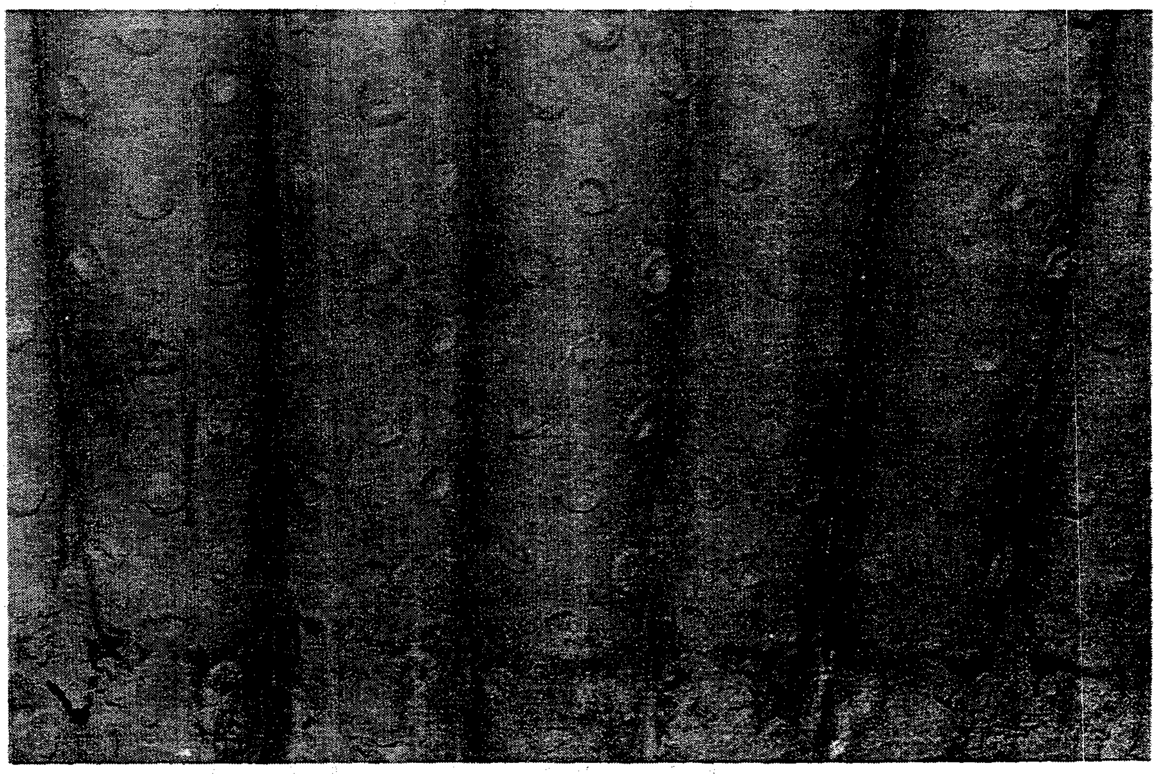
ELEVATION 909'



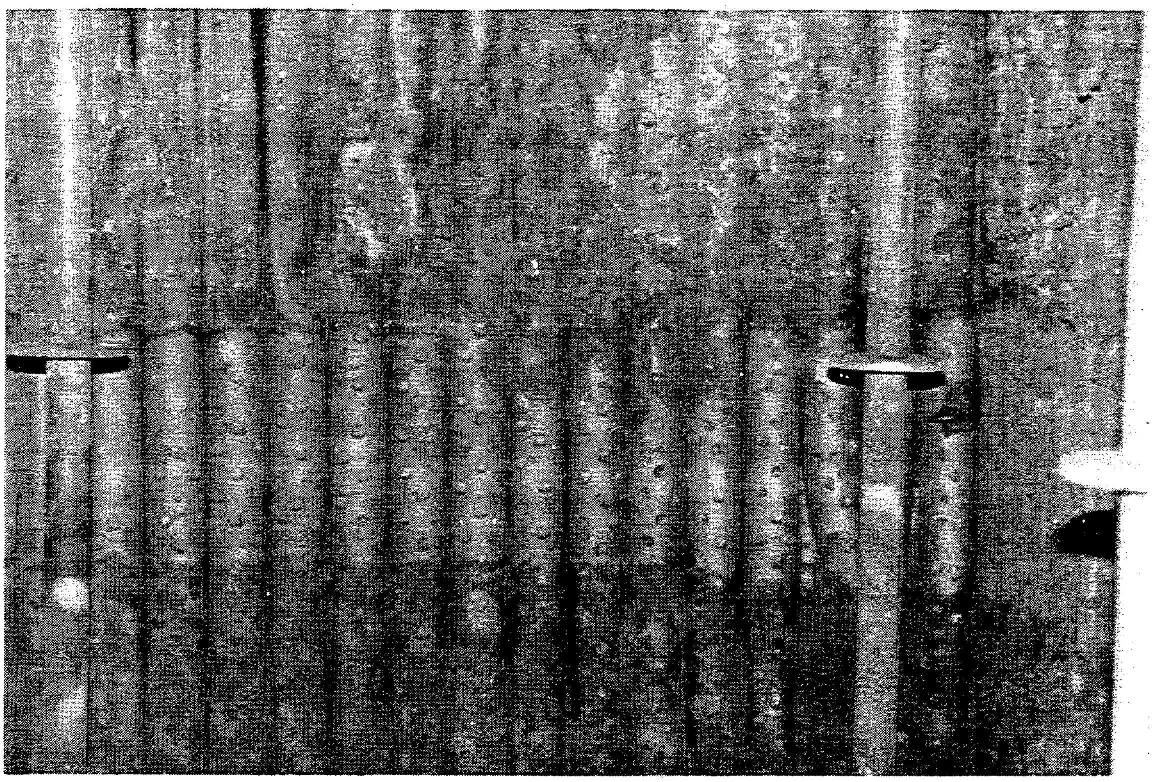


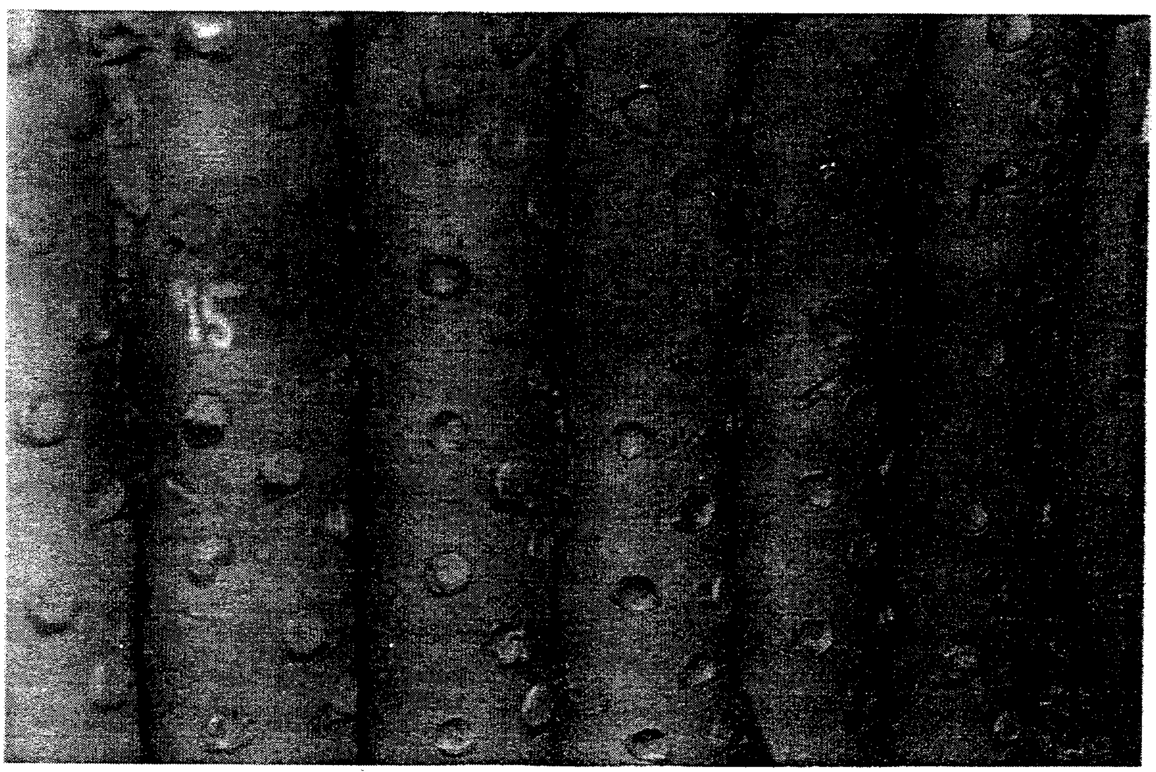
ELEVATION 902'



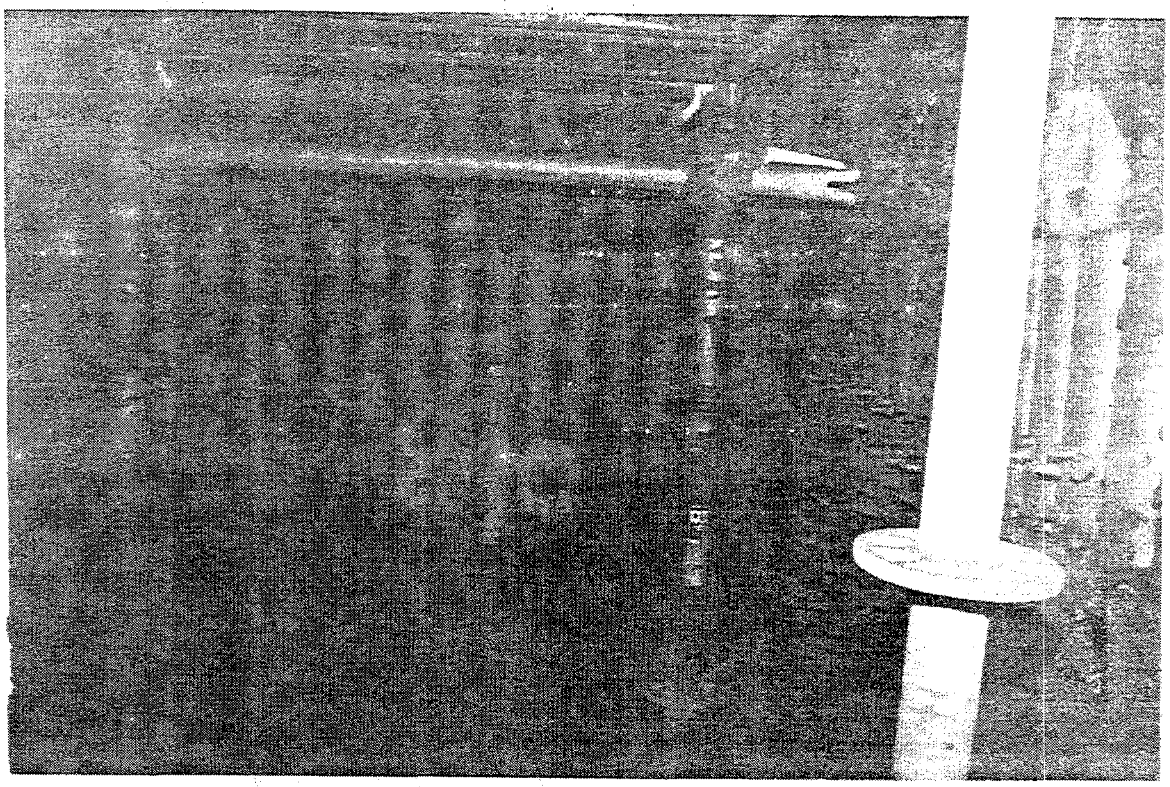


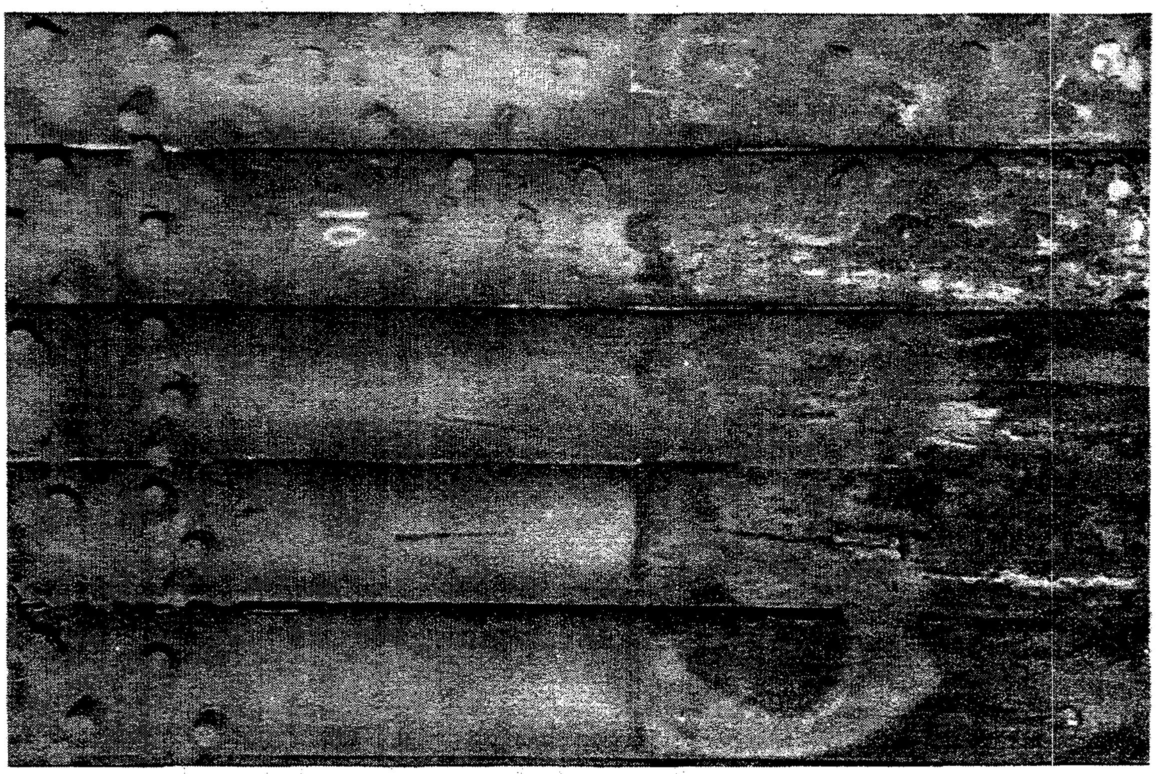
ELEVATION 896'



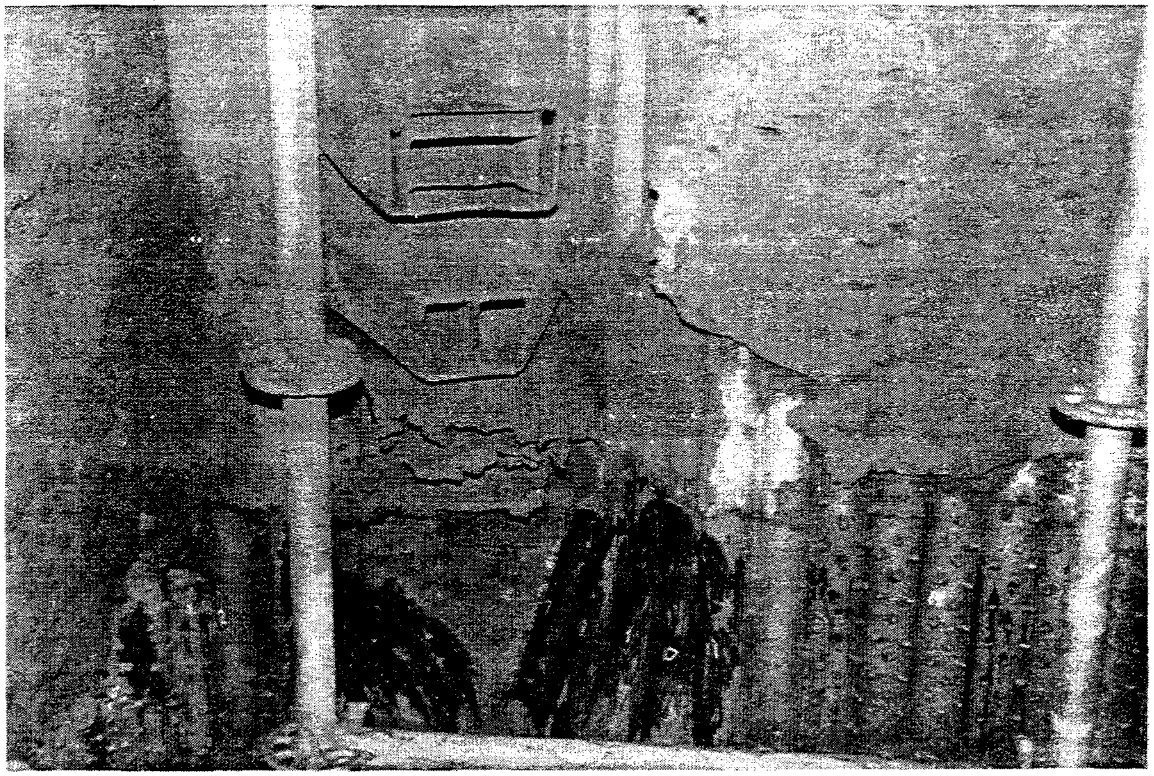


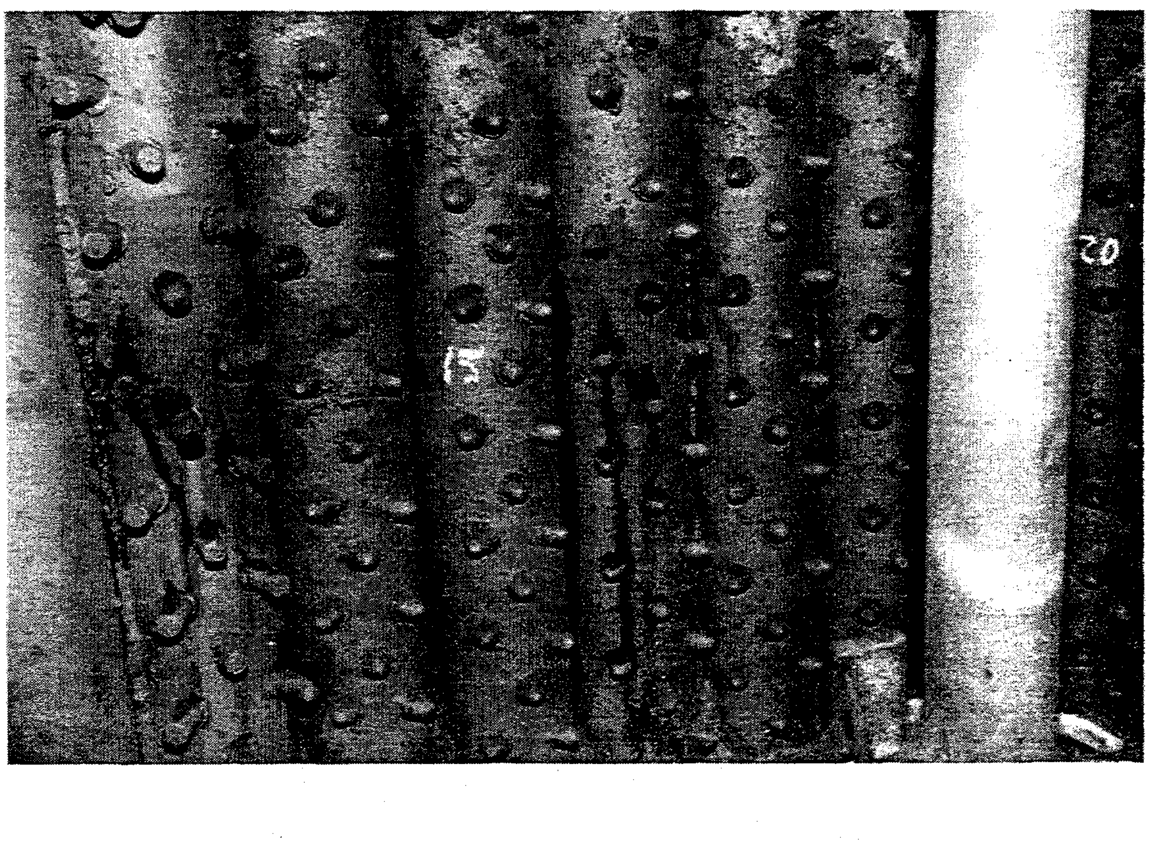
ELEVATION 890′





ELEVATION 880'





APPENDIX C

INTERIM FIELD TEST REPORT

W. R. Roczniak

ABB Power Plant Laboratories
Research and Technology
A Division of Combustion Engineering, Inc.
Windsor, Connecticut 06095-0500

April 23, 1992

Synopsis of Appendix C

This appendix summarizes the results of boiler tube corrosion investigations conducted for the Ohio Edison reburn project through April 1992.

April 23, 1992

Sher M. Durrani
Gen. Proj. Engr.
Ohio Edison
76 South Main St.
Akron, OH 44308

Attached is the interim report presenting the data associated with corrosion potential of surfaces obtained at pre-start of testing, after parametric testing and after base line testing.

The corrosion probes show no significant wastage during the first two phases of testing. The U.T. measurements taken after completion of the parametric testing phase and the base line test phase are inconsistent. The original readings obtained prior to testing, of the secondary superheater stages suggest that the tubing walls were either much higher than the specifications or that an adherent scale remained. Thus, they appear to be inconsistent with the readings obtained during parametric and base line data or may have been obtained with a different instrument.

The waterwall measurements are similar for the pre-start data with the base line data but for the parametric test data the readings are lower, of course, the tubing could not have increased in thickness during operation.

The measurements to be taken after completion of the reburn phase will be incorporated in these plots and should assist in resolving the U.T. measurement inconsistencies reported thus far.

W. R. Roczniak
W. R. Roczniak

WRR/haw

cc: R. Borio
A. L. Plumley
R. Lewis

ABB Combustion Engineering Systems

Combustion Engineering, Inc.
1000 Prospect Hill Road
Post Office Box 500
Windsor, Connecticut 06095-0500
Telephone (203) 688-1911
Fax (203) 285-9512
Telex 99297 COMBEN WSOR

INTERIM FIELD TEST REPORT

INTRODUCTION

This report presents the data associated with corrosion potential of surfaces obtained during the parametric phase and the base line phase of the test program in preparation for the reburn phase operation. These data were utilized to determine any accelerated wastage during parametric testing and to establish a wastage rate during normal operating parameters and will be used for comparison to similar data generated during the reburn phase of the program.

BACKGROUND

Several studies have been conducted over the last twenty years to evaluate the reduction of NOx in utility steam generators. The prime goal of these studies was the assessment of the effectiveness of the processes and/or modifications employed to achieve NOx reduction. A secondary goal was to determine the effects of the low NOx operating conditions on wastage rates in these test vehicles. The determination of these wastage rates was obtained by the direct measurement of heat surfaces by ultra sonic techniques (UT), and by the use of temperature controlled corrosion probes or by the utilization of integral test sections. The integral test sections were documented metallographically prior to installation and removed after completion of the test for metallographic evaluation. The U.T. measurements were obtained prior to initiation of the test and at fixed intervals during the test program. The temperature controlled probes were installed and removed from the unit without requiring unit outages.

Operating these units at minimal excess oxygen could potentially increase the wastage rates by interrupting the formation of protective oxide coatings, thus influencing the rate of wastage.

In the previous test programs, accelerated wastage was not reported under any of the test conditions studied.

FIELD TEST PROGRAM

The test program in the "Reburn" study conducted in Ohio Edison's Niles Unit No. 1, was scheduled to be completed in a two year period. This program employs the use of temperature controlled corrosion probes and extensive U.T. measurements between several phases of the program. The large number and frequency of U.T. measurements was requested by Ohio Edison. The measurements were obtained prior to the start of parametric testing, after the short term parametric tests (approximately three weeks of demonstrations in a six month period) and after the base line data were established. This program consists of three phases of testing, i.e., 1) The parametric testing to establish operating parameters, 2) the base-line phase (approximately one year of operation) and 3) the long term reburn phase.

The U.T. measurements were taken at five elevations in the furnace cavity and just above the rear wall bend in the furnace cavity. Also, the leading tubes of each element of the secondary superheater stages and the reheater were measured at three distances (1/4, 1/2, 3/4 the tube length) of each of the stages. Reference marks were inscribed at the test elevations to facilitate measuring the same locations at each outage.

Eight temperature controlled corrosion probes were exposed in the waterwall openings installed for this purpose. Two probes were located in the rear wall along with one probe on each side wall at the lowest elevation, which was just above the gas injection nozzles in the unit. Two probes were installed at mid-point of the side walls, one on each side wall, and two probes just below the entrance into the secondary superheater portion of the furnace. In addition to these waterwall probes, a superheater probe was installed between the fourth and fifth stages of the secondary superheater.

The complete set of probes were utilized during the base-line phase of the program and were installed for the reburn phase of the program. A limited number of waterwall probes was requested for the parametric testing, which was not within the original scope of the program.

SELECTION OF ALLOYS

Materials to be evaluated during these tests were the materials of construction utilized in the furnace. These included carbon steel, T-11 material (1½% Chromium - ½% Molybdenum), T-22 material (2¼% Chromium - 1% Molybdenum) and T-9 material (9% Chromium - 1%

Molybdenum). Materials not utilized in fabrication of the unit included T-91 material (a modified T-9 material), 304ss material (18% Chromium - 8% Nickel) and 310ss material (25% Chromium - 20% Nickel). These additional materials were selected for evaluation to determine their effectiveness in this environment should accelerated wastage occur to the materials of fabrication.

TEST PROBES

Each of the waterwall probes was composed of five (5) threaded test rings machined to fixed dimensions for insertion in the test locations. The superheater probe consisted of fifteen (15) test rings which were held on the assembly by spring tension.

The hardware to control temperature, log, average and store temperature profile data consists of a diskless industrial computer, thermocouple input cards, and an analog output card with digital I/O lines. The analog output is used to control the proportioning air valves, and the digital I/O for sensing limit switch status for enunciating alarms. All control equipment is mounted in a dust-tight air conditioned enclosure. Data retrieval capability utilizing a telephone modem provides a mechanism to monitor the operational status of the probes.

RESULTS

The corrosion probes exposed during the parametric testing phase were removed from the unit in December of 1990. The test results of the ring specimens are shown in Table 1. The table shows the weight loss of the materials from the probes exposed at the four elevations of the furnace. Also included in the table are the maximum wall penetrations measured by micrometer. Minimal weight loss differences were noted between the carbon steel rings and the T-22 material. The 304ss material was the least affected of these probe rings.

The wastage rates of the corrosion probes exposed during the base line test phase of the program are found in Table 2. The waterwall probes in the rear wall at the lowest elevation experienced exposure at high temperature above the control limits established for the test and consequently greater wastage. All of the other probes operated within the preset temperature limits. The top elevation experienced the highest wall penetrations of the remaining probes. These probes were exposed from January 1991 into October 1991.

During the October outage, modifications were made to the reburn system. Several random tubes located in the gas injector nozzle openings were removed for physical evaluation in the laboratory. These were from the outer extremes of the assemblies near the straight tubes in the furnace cavity. A schematic of the tubes is shown in Figure 1. The micrometer measurements of the rings after cleaning are located in Table 3. These measurements assume the bench mark as position A. The benchmark reading is the lowest in all of the test rings. As a general rule the backside of the tube is usually the highest reading of exposed tubing but the measurements show no appreciable wastage. The benchmark was established by the studs and the position of the external deposits located on the surface of the tubes. Also noted is stud burn back both in diameter and length.

The superheater corrosion probe was also removed in December of 1990. The test results of the specimens are shown in Table 4. The table shows the weight loss of the materials as well as the maximum penetration for each test ring. The weight loss is shown as a function of time of exposure in Figure 2. Weight loss is shown increasing with exposure at increasing metal temperature. Associated with this is the resistance to corrosion of the metals containing increased chromium concentration. The effect of temperature is shown in the data shown at the highest exposure time. These test rings were also exposed at lower temperatures than the other two exposure times shown in the Figure.

ULTRASONIC WALL THICKNESS MEASUREMENTS

U.T. measurements were obtained during each outage and prior to initiating parametric testing. All the measurement were plotted for each elevation (see Figures 3-12).*

WATERWALL MEASUREMENTS

The front wall (Figures 3) shows that no accelerated wastage has occurred over the entire length of the wall. These measurements show 5 to 10 mils from June 1990 to October 1991. Both the

*The original Figures 3-12 were updated in August 1992.

right and left wall measurements (Figures 4 & 5) show no accelerated wastage. Isolated tubes were measured and resulted in readings higher than the earlier outage measurement. This apparently is erroneous since the tubes can not gain thickness during exposure. The rear wall generated the same type of conditions (Figure 6). Accelerated external wastage was not detected on any wall.

The rear wall just above the wall bend at elevation 909, had several specific tubes which were considered below specification. The outward appearance displayed no wear flattening, corrosion, or erosion. These tubes were reported to have internal wastage and Ohio Edison is aware of the conditions of these tubes.

SUPERHEATER MEASUREMENTS

Ultrasonic thickness measurements were obtained at 1/4, 1/2 and 3/4 points of every tube in the lower tube bank of each stage of the convection section (superheater & reheater bundles). See Figures 7-12.

Wastage in general was slight except for the 15 tubes in the center section of the 4th and 5th stages. Apparent metal losses of up to 80 mils were observed on these few tubes (Figures 9 & 10) in a pattern suggesting that soot blower erosion or poor gas distribution coupled with fly ash carryover were accelerating the wastage. Note that the thinning continued and even accelerated during the period January to October 1991 when no reburn activity was occurring.

The UT measuring team had noted that the tubes were polished in a pattern more typical of erosion than corrosion. The locations of these areas were reported to Ohio Edison personnel at the time.

INTERIM TEST CONCLUSIONS

The data generated by the corrosion probes indicate increased penetration of the materials with elevation in the boiler. Review of the three sets of ultrasonic thickness readings obtained at pre-selected elevations on the waterwalls and in the convection section does not appear to indicate that there was any excessive general wastage occurring during the past 1 1/2 years of operation with or without reburn.

Waterwall measurements showed variations of ± 5 to 10 mils between June 1990 and October 1991. The superheater and reheater measurements were also consistant at all three outages with one exception. The center 15 tubes in the 4th and 5th stages of the superheater bundles were found to have measurable thinning in a pattern which suggests sootblower erosion or excessive carryover of ash due to mal distribution. The phenomenon was observed even at the time of the original baseline tube measurements prior to any reburn activity.

TABLE 1

CORROSION PROBES
PARAMETRIC TESTING

JUNE 1990 - DECEMBER 1990

LOWEST ELEVATION - RIGHT SIDE

	MAXIMUM WEIGHT LOSS	MAXIMUM WALL PENETRATION
LOWEST ELEVATION - RIGHT SIDE		
CARBON STEEL	0.13 GRAMS/IN^2	0.001"
T-22	0.12 GRAMS/IN^2	0.001"
304ss	0.04 GRAMS/IN^2	NONE MEASURED
LOWEST ELEVATION		
CARBON STEEL	0.09 GRAMS/IN^2	0.001"
T-22	0.07 GRAMS/IN^2	0.001"
304ss	<0.01 GRAMS/IN^2	NONE MEASURED
MIDDLE ELEVATION*		
CARBON STEEL	0.12 GRAMS/IN^2	0.001"
T-22	0.12 GRAMS/IN^2	0.001"
304ss	0.01 GRAMS/IN^2	0.001"
TOP ELEVATION		
CARBON STEEL	0.04 GRAMS/IN^2	0.001"
T-22	0.04 GRAMS/IN^2	0.001"
304ss	<0.01 GRAMS/IN^2	NONE MEASURED

* PROBE EXPERIENCED HIGH TEMPERATURE

TABLE 2

CORROSION PROBES
BASE LINE TESTING

JANUARY 1991 - OCTOBER 1991

LOWEST ELEVATION - RIGHT SIDE

LOWEST ELEVATION - RIGHT SIDE	MAXIMUM WEIGHT LOSS	MAXIMUM WALL PENETRATION
CARBON STEEL	0.78 GRAMS/IN^2	4 MILS
T-22	0.66 GRAMS/IN^2	6 MILS
304ss	1.0 GRAMS/IN^2	1 MIL
*REAR RIGHT SIDE		
CARBON STEEL	2.12 GRAMS/IN^2	14 MILS
T-22	3.42 GRAMS/IN^2	23 MILS
304ss	2.60 GRAMS/IN^2	21 MILS
*REAR LEFT SIDE		
CARBON STEEL	2.90 GRAMS/IN^2	16 MILS
T-22	1.42 GRAMS/IN^2	8 MILS
304	3.14 GRAMS/IN^2	11 MILS
LEFT SIDE		
CARBON STEEL	0.54 GRAMS/IN^2	2 MILS
T-22	0.30 GRAMS/IN^2	1 MIL
304	0.14 GRAMS/IN^2	<1 MIL

MIDDLE ELEVATION - RIGHT SIDE	MAXIMUM WEIGHT LOSS	MAXIMUM WALL PENETRATION
CARBON STEEL	0.18 GRAMS/IN^2	1 MIL
T-22	0.24 GRAMS/IN^2	1 MIL
304	0.04 GRAMS/IN^2	1 MIL
LEFT SIDE		
CARBON STEEL	0.92 GRAMS/IN^2	4 MILS
T-22	0.92 GRAMS/IN^2	5 MILS
304	0.12 GRAMS/IN^2	1 MIL
TOP ELEVATION - RIGHT SIDE		
CARBON STEEL	2.92 GRAMS/IN^2	7 MILS
T-22	1.32 GRAMS/IN^2	4 MILS
304	0.18 GRAMS/IN^2	<1 MIL
LEFT SIDE		
CARBON STEEL	2.08 GRAMS/IN^2	10 MILS
T-22	1.28 GRAMS/IN^2	5 MILS
304	0.08 GRAMS/IN^2	<1 MIL

* OVERHEATED

TABLE 3

Wall Thickness Measurements of Waterwall Tubes
Removed in October 1991

	Position			Bench Mark
	B	C	D	A
Tube 1	0.257	0.262	0.262	0.254
Tube 2	0.259	0.258	0.256	0.255
Tube 3	0.257	0.257	0.257	0.256
Tube 4	0.259	0.261	0.257	0.253

STUDS	Diameter	Length
Tube 1 (1 stud)	0.430	0.794
Tube 2 (2 studs)	0.438	0.810
	0.444	0.798
Tube 3 (2 studs)	0.477	0.850
	0.460	0.865
Tube 4 (2 studs)	0.442	0.857
	0.450	0.820

TABLE 4

Superheater Corrosion Probes Weight Loss Data
Includes Time of Exposure and Temperature
Metal Temperature of Test Rings

Ring No.	Material	Weight Loss in Grams	Weight Loss Gram/in^2	Temperature °F	Length of Exposure
1	T-22	3.236	0.26	910	5800 hours
2	T-22	4.812	0.39	930	"
3	T-91	2.439	0.19	950	"
4	T-91	3.432	0.27	970	"
5	304ss	1.105	0.09	990	"
6	T-11	12.225	0.98	1010	"
7	T-22	11.746	0.94	1030	5800 hours
8	T-22	14.706	1.18	1050	"
9-1	T-91	1.638	0.13	1070	1500 hours
10-1	T-91	1.766	0.14	1090	"
11-1	304ss	0.165	0.01	1110	"
12-1	T-22	4.746	0.38	1130	"
13-1	T-91	2.019	0.16	1150	"
14-1	304ss	0.123	0.01	1170	"
15-1	310ss	0.061	0.01	1190	1500 hours
9-2	T-91	4.950	0.39	1070	4300 hours
10-2	T-91	6.389	0.51	1090	"
11-2	304ss	1.336	0.11	1110	"
12-2	T-22	25.607	2.05	1130	"
13-2	T-91	4.942	0.39	1150	"
14-2	304ss	0.968	0.08	1170	"
15-2	310ss	0.349	0.03	1190	"

WRR/05-92.wp

FIGURE 1

SCHEMATIC OF MEASUREMENT LOCATIONS OF WATERWALL TUBES REMOVED DURING OCTOBER 1991 OUTAGE

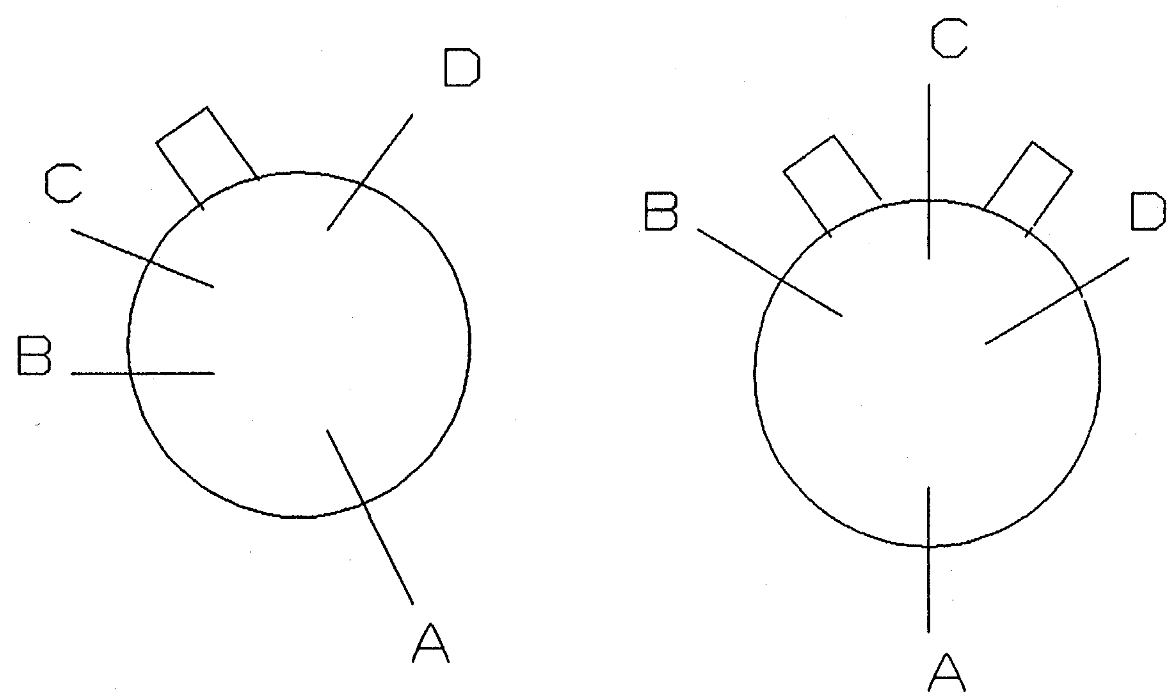
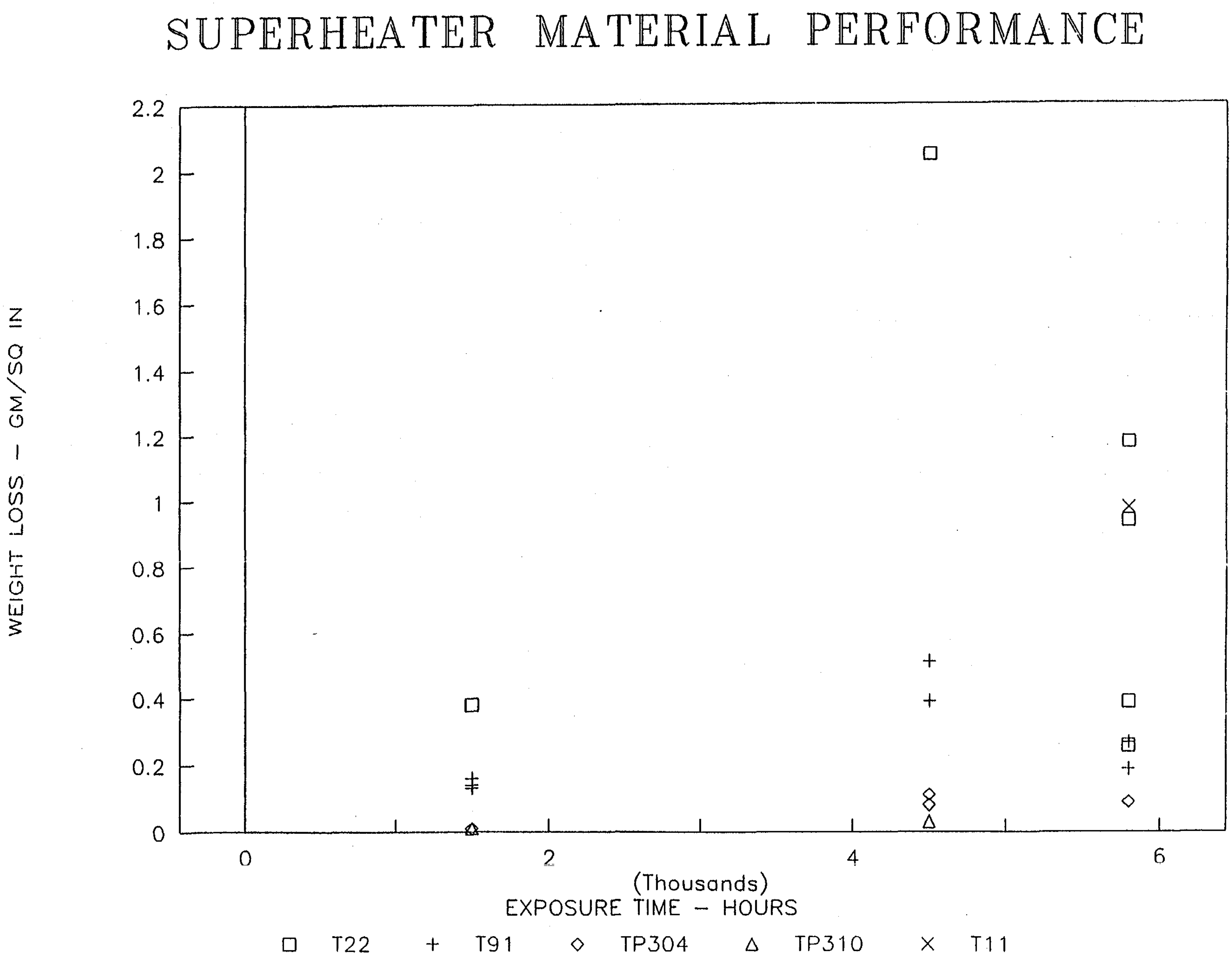
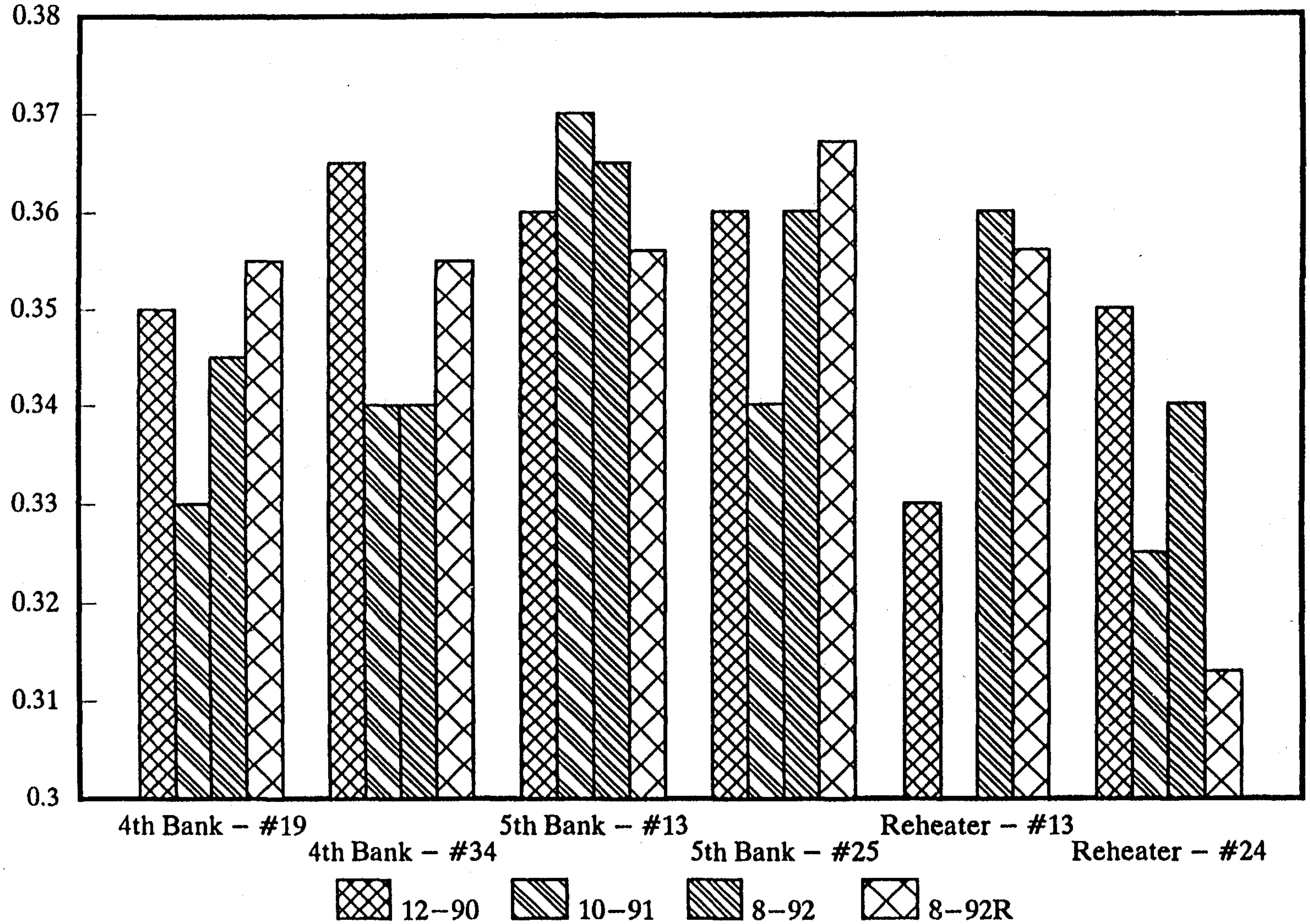


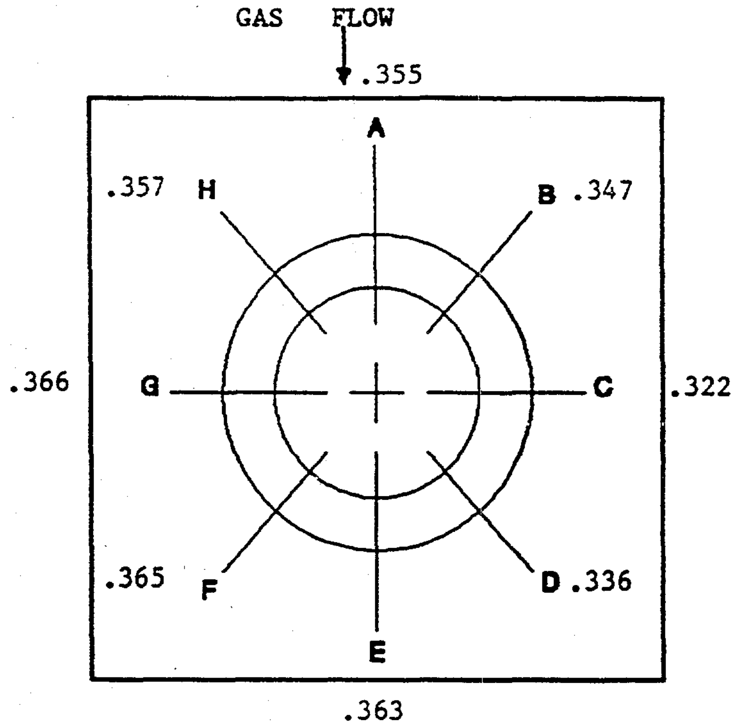
FIGURE 2



SUPERHEATER MATERIAL PERFORMANCE
WEIGHT LOSS – GM/SQ IN
2.2
2
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
0
2
4
6
(Thousands)
EXPOSURE TIME – HOURS
T22
T91
TP304
TP310
T11

In–situ Tubes



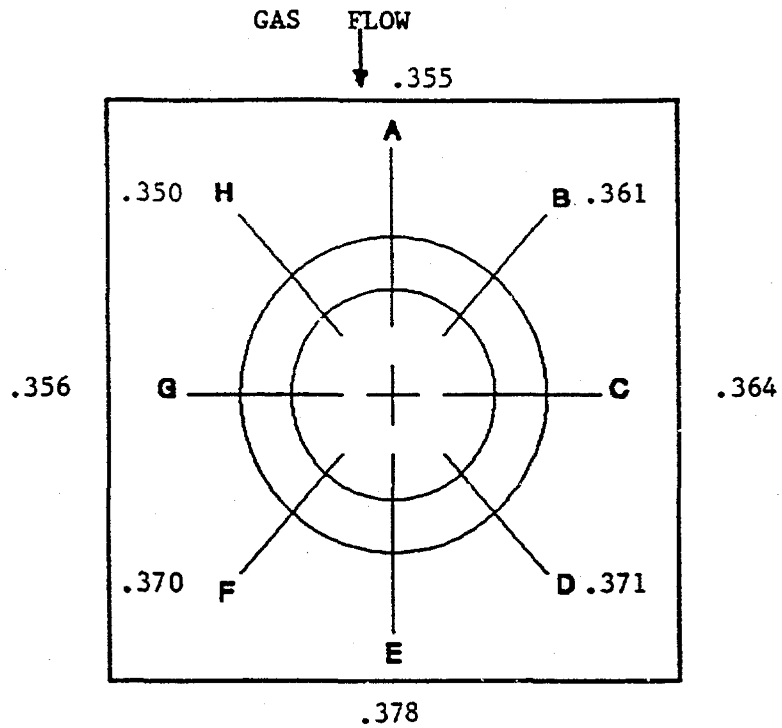


4TH BANK

TUBE #19

UT MEASUREMENTS

DATE	REAR	MIDDLE	FRONT
6-90	0.320	0.320	0.325
12-90	0.365	0.350	0.300
10-91	0.305	0.330	0.290
8-92	0.295	0.345	0.290

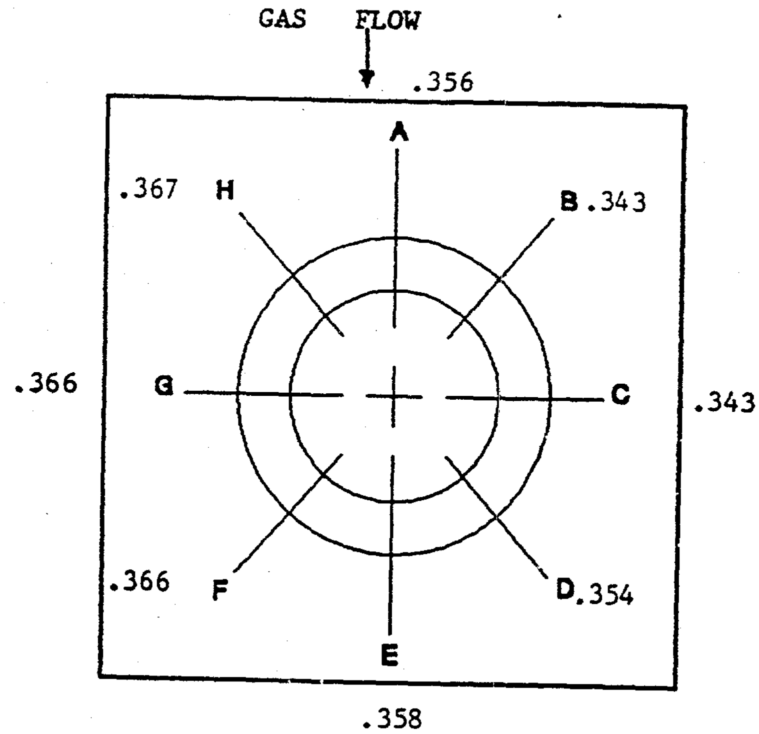


4TH BANK

TUBE #34

UT MEASUREMENTS

DATE	REAR	MIDDLE	FRONT
6-90	0.340	0.350	0.350
12-90	0.380	0.365	0.315
10-91	0.345	0.340	0.320
8-92	0.340	0.340	0.320

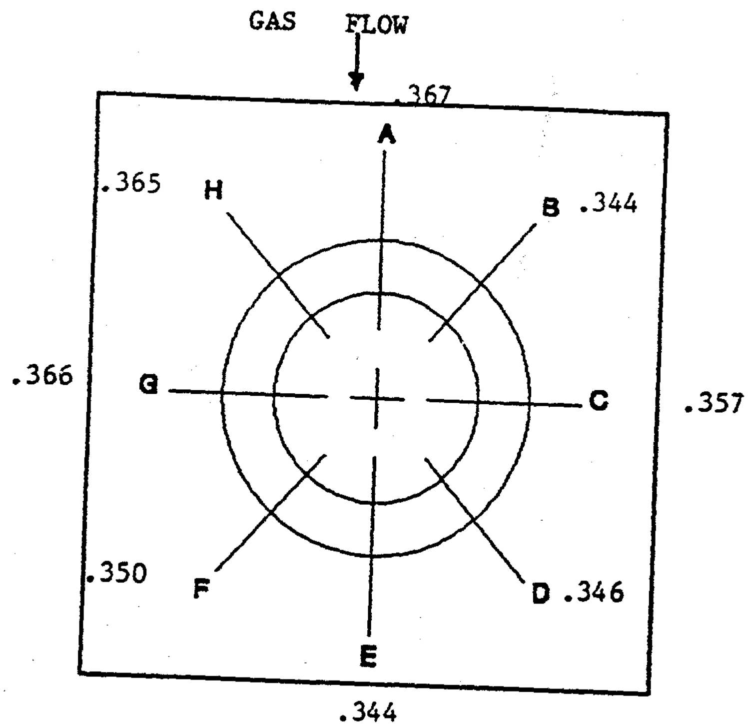


5TH BANK

TUBE #13

UT MEASUREMENTS

DATE	REAR	MIDDLE	FRONT
6-90	0.370	0.350	0.385
12-90	0.375	0.360	0.350
10-91	0.350	0.370	0.350
8-92	0.380	0.365	0.390

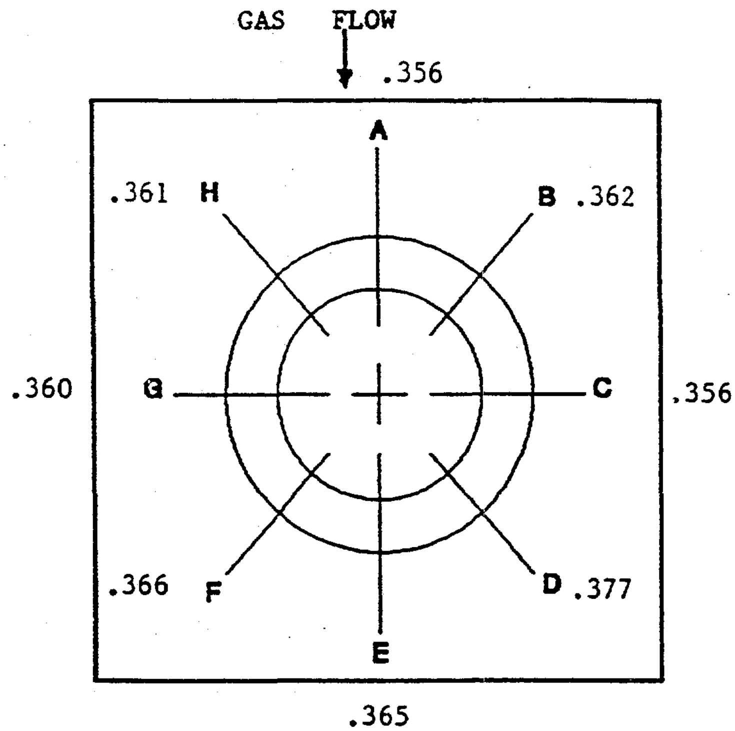


5TH BANK

TUBE #25

UT MEASUREMENTS

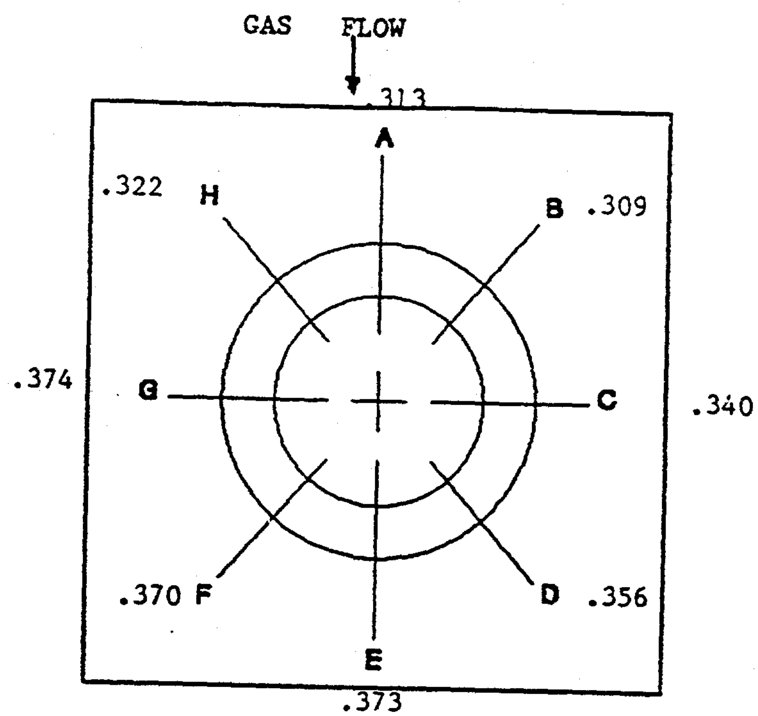
DATE	REAR	MIDDLE	FRONT
6-90	0.405	0.385	0.400
12-90	0.385	0.360	0.360
10-91	0.360	0.340	0.330
8-92	0.360	0.360	0.360



REHEATER TUBE #13

UT MEASUREMENTS

DATE	REAR	MIDDLE	FRONT
6-90	0.350	0.355	0.350
12-90	0.320	0.330	0.340
10-91	0.330	-----	0.325
8-92	0.335	0.360	0.345



REHEATER TUBE #24

UT MEASUREMENTS

DATE	REAR	MIDDLE	FRONT
6-90	0.340	0.330	0.340
12-90	0.340	0.350	0.315
10-91	0.300	0.325	0.315
8-92	0.300	0.340	0.325

SUPERHEATER CORROSION PROBES WEIGHT LOSS DATA

INCLUDES TIME OF EXPOSURE AND TEMPERATURE

METAL TEMPERATURE OF TEST RINGS

Ring No.	Material	Weight Loss in Grams	Weight Loss Gram/in^2	Temp. °F	Length of Exposure
202	T-22	12.179	0.98	910	2000
203	T-22	2.774	0.22	930	2000
204	T-9	1.540	0.12	950	2000
205	T-9	2.011	0.16	970	2000
206	304ss	0.414	0.03	990	2000
207	T-11	4.441	0.36	1010	2000
208	T-22	5.082	0.41	1030	2000
209	T-22	6.743	0.54	1050	2000
210	T-91	2.644	0.21	1070	1400
211	T-9	3.116	0.25	1090	1400
212	304ss	1.020	0.08	1110	1400
213	T-22	4.417	0.35	1130	1400
214	T-9	1.325	0.11	1150	1400
215	304ss	0.364	0.03	1170	1400
216	310ss	0.191	0.02	1190	1400
145-2	T-91	1.859	0.15	1070	600
146-2	T-92	1.986	0.16	1090	600
147-2	304ss	0.380	0.03	1110	600
148-2	T-22	3.566	0.28	1130	600
149-2	T-91	0.672	0.05	1150	600
150-2	304ss	0.110	0.01	1170	600
151-2	310ss	0.076	0.01	1190	600

SUPERHEATER MATERIAL PERFORMANCE